



BUILDING

value through disciplined
financial management



Common Investor Questions

Q: What is Petro-Canada's strategy to create shareholder value?

A: The Company's strategy for shareholder value creation is clear and concise. First, Petro-Canada is improving the profitability of the base business. Second, the Company is using a disciplined approach to long-term growth by applying three tactics: leveraging existing assets, pursuing new opportunities with a focus on long-life assets and building a balanced exploration program.

Q: What is Petro-Canada's cumulative total shareholder return for the last 10 years?

A: Including price appreciation and dividends, Petro-Canada's total shareholder return has been 507%. Petro-Canada shares have outperformed both the total shareholder returns of the Toronto Stock Exchange (TSX)/Standard & Poor's (S&P) index (160%) and the New York Stock Exchange (NYSE) S&P 500 index (168%).

Q: Does Petro-Canada have a share repurchase program?

A: Yes. On June 18, 2004, the TSX approved Petro-Canada's application to make a normal course issuer bid to purchase up to 21 million shares until June 21, 2005. As at December 31, 2004, the Company had repurchased and cancelled approximately 6.9 million shares.

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LEGAL NOTICE – FORWARD-LOOKING INFORMATION

The following Annual Report contains forward-looking statements. Such statements are generally identifiable by the terminology used, such as "plan," "anticipate," "intend," "expect," "estimate," "budget" or other similar wording. Forward-looking statements include, but are not limited to, references to future capital and other expenditures, drilling plans, construction activities, the submission of development plans, seismic activity, refining margins, oil and natural gas production levels and the sources of growth thereof, results of exploration activities, and dates by which certain areas may be developed or may come on-stream, retail throughputs, pre-production and operating costs, reserves estimates, reserves life, natural gas export capacity and environmental matters. These forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and natural gas prices; refining and marketing margins; the ability to produce and transport crude oil and natural gas to markets; the effects of weather conditions; the results of exploration and development drilling and related activities; fluctuation in interest rates and foreign currency exchange rates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; changes in environmental and other regulations; risks attendant with oil and gas operations; and other factors, many of which are beyond the control of Petro-Canada. These factors are discussed in greater detail in filings made by Petro-Canada with the Canadian provincial securities commissions and the United States (U.S.) Securities and Exchange Commission (SEC).

Readers are cautioned that the foregoing list of important factors affecting forward-looking statements is not exhaustive. Furthermore, the forward-looking statements contained in this Annual Report are made as of the date of this Annual Report, and Petro-Canada does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this Annual Report are expressly qualified by this cautionary statement.

Petro-Canada's staff of qualified reserves evaluators generates the reserves estimates used by this Company. Our reserves staff and management are not considered independent of the Company for purposes of the Canadian provincial securities commissions. Petro-Canada has obtained an exemption from certain Canadian reserves disclosure requirements to permit it to make disclosure in accordance with SEC standards in order to provide comparability with U.S. and other international issuers. Therefore, Petro-Canada's reserves data and other oil and natural gas formal disclosure is made in accordance with U.S. disclosure requirements and practices and may differ from Canadian domestic standards and practices. Where the term barrel of oil equivalent (boe) is used in this Annual Report, it may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (Mcf): one barrel (bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The use of terms such as "probable," "possible," "recoverable" or "potential" reserves and resources in this Annual Report does not meet the guidelines of the SEC for inclusion in documents filed with the SEC.

2004 Petro-Canada Highlights

From both a financial and strategic point of view, 2004 was a strong year for Petro-Canada. Specifically, we:

- achieved record earnings from operations of \$1.9 billion and record cash flow of \$3.7 billion;
- met upstream production targets due to a balanced portfolio;
- acquired interests in the U.S. Rockies and the United Kingdom (U.K.) sector of the North Sea, positioning us for future growth; and
- completed most of the work to consolidate Eastern Canada refineries and increased sales at convenience stores and of high-margin lubricants.

2004 CASH FLOW (%)

North American Natural Gas

- Sustained solid North American Natural Gas production of 695 million cubic feet per day (MMcf/d);
- Grew production and skills in unconventional gas through U.S. Rockies acquisition.

24%

Who is Petro-Canada?

We are an integrated oil and gas company with a portfolio of businesses spanning both the upstream and downstream sectors of the industry. In the upstream businesses, we explore for, develop, produce and market crude oil, natural gas liquids and natural gas in Canada and internationally. The Downstream business refines crude oil and other feedstocks, and markets and distributes petroleum products and related goods and services, primarily in Canada. Our shares trade on the TSX under the symbol PCA and on the NYSE under the symbol PCZ.

East Coast Oil

- Achieved high netback production of 78,200 barrels per day (b/d) net to Petro-Canada;
- Advanced development of the White Rose project during 2004.

26%

Oil Sands

- Recorded highest ever production at Syncrude;
- Improved reliability at MacKay River.

9%

International

- Progressed North Sea developments for added production in 2005-2006;
- Acquired interest in Buzzard project to add significantly higher netback production starting in late 2006.

27%

Downstream

- Increased sales of high-margin lubricants to 67% of total sales, increased convenience store sales 11% and drove same store sales up 7%;
- Completed majority of consolidation of Eastern Canada refineries.

14%

MANAGEMENT'S DISCUSSION AND ANALYSIS

*This Management's Discussion and Analysis (MD&A), dated effective as of February 16, 2005, should be read in conjunction with the audited Consolidated Financial Statements and Notes for the year ended December 31, 2004, included in the 2004 Annual Report and the 2004 Annual Information Form. Financial data has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), unless otherwise specified. All dollar values are Canadian dollars, unless otherwise indicated. All oil and natural gas production and reserves volumes are stated before deduction of royalties, unless otherwise indicated. **Graphs accompanying the text identify our "value drivers," the key measures of performance in each segment of our business.** Glossary of financial terms and ratios can be found on the inside back cover of this report.*

NON-GAAP MEASURES

Cash flow, which is expressed before changes in non-cash working capital, is used by the Company to analyze operating performance, leverage and liquidity. Earnings from operations, which represent net earnings excluding gains or losses on foreign currency translation, disposal of assets and unrealized gains or losses on the mark-to-market of the derivative contracts associated with the Buzzard acquisition, are used by the Company to evaluate operating performance. Cash flow and earnings from operations do not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other companies.

Q:

What is Petro-Canada's outlook for the business environment?

A:

Signs point to commodity markets which have rising demand and continued price volatility.

Business Environment

Economic factors influencing Petro-Canada's upstream businesses financial performance include crude oil and natural gas prices and foreign exchange rates, particularly the Canadian dollar/U.S. dollar exchange rate. Prices for energy commodities are primarily affected by market supply and demand, weather and political events. Performance in Petro-Canada's Downstream business is influenced mainly by the level and volatility of crude oil prices, industry refining margins, movement in crude oil price differentials, demand for refined petroleum products and the degree of market competition.

BUSINESS ENVIRONMENT IN 2004

The year 2004 was an extraordinary year in the history of energy commodity prices. International light crude oil prices for North Sea Brent (Brent) and West Texas Intermediate (WTI) reached average annual prices not seen since 1982. Light/heavy crude price differentials widened to unprecedented levels. North American natural gas prices attained their highest level since price deregulation in 1986.

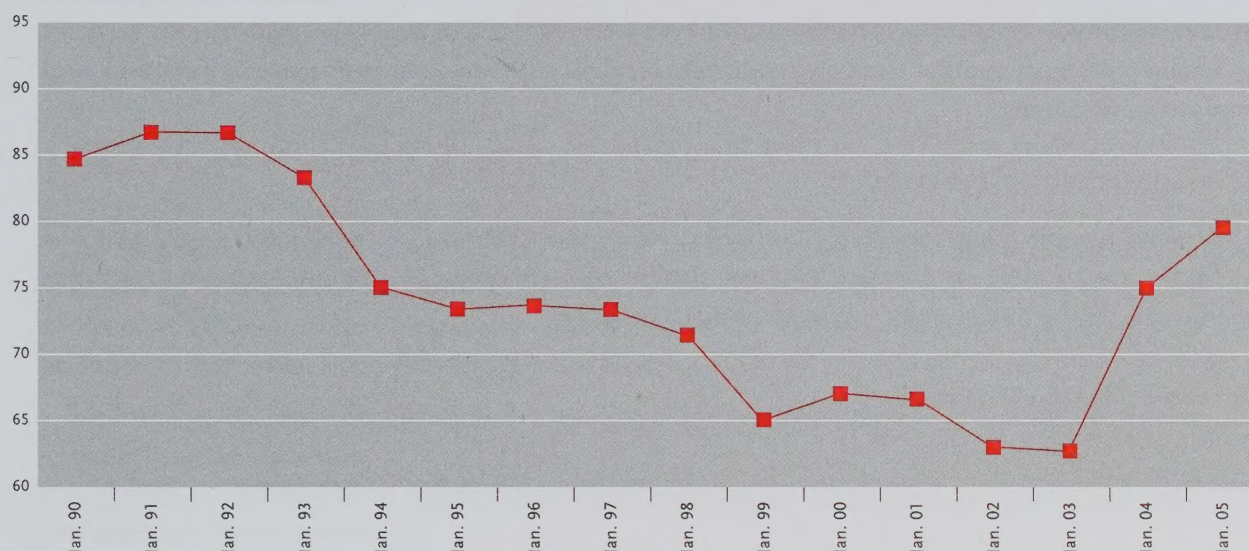
The factors driving high oil prices were: a strong surge in global oil demand (led by China); slower growth in Russian production; continued interruption of Iraqi exports; and the impact of Hurricane Ivan on the U.S. Gulf of Mexico production. At the same time, increased production from the Organization of the Petroleum Exporting Countries (OPEC) and Mexico led to the supply of heavier grades of crude growing at a faster rate than the refining conversion capacity that was available for processing. The result was the widest light/heavy crude price differential on record.

Continued weakening of the U.S. dollar throughout 2004 resulted in the highest Canada/U.S. exchange rate in the past 10 years. The elevated exchange rate lowered the positive impact of higher international commodity prices. The Canadian dollar rose from 77.4 cents US on December 31, 2003, to 83.1 cents US on December 31, 2004, an increase of 7%.

The stronger Canadian dollar dampened the impact of higher commodity prices in 2004.

CANADA/U.S. EXCHANGE RATE

(US cent/Cdn \$, January 1990 to January 2005)



North American natural gas prices enjoyed another year of buoyancy, despite record levels of storage gas due to weaker demand and better-than-anticipated production volumes. Concern regarding the underlying strength of production growth in North America and the impact of Hurricane Ivan on U.S. Gulf of Mexico production helped maintain Henry Hub monthly average gas prices at levels above \$5.00 US per million British thermal units (MMBtu). Average Canadian natural gas prices mirrored the performance of prices south of the border, up from 2003 despite a substantial widening of the price differential between the Henry Hub and the AECO-C spot price.

In the Canadian downstream sector, refined petroleum product sales grew by about 4%, compared to 4.8% in 2003. Refining margins improved again in 2004, largely in response to bottlenecks in the North American refining system. The system continues to be stretched to its limit by a combination of growing refined product demand and increasingly stringent mandated product specifications. As well, record light/heavy crude price differentials contributed to downstream margin improvements.

Commodity Price Indicators and Exchange Rates

(averages for the years indicated)

	2004	2003
Crude oil price indicators (per barrel):		
Dated Brent at Sullom Voe	US\$ 38.21	28.84
WTI at Cushing	US\$ 41.40	31.04
WTI/Brent price differential	US\$ 3.19	2.20
Brent/Maya price differential	US\$ 8.20	4.60
Edmonton Light	Cdn\$ 52.78	43.77
Edmonton Light/Lloydminster Blend (heavy) price differential	Cdn\$ 17.07	12.68
Natural gas price indicators:		
Henry Hub – per MMBtu	US\$ 6.09	5.44
AECO-C spot – per Mcf	Cdn\$ 7.08	6.99
Henry Hub-AECO-C basis differential – per MMBtu	US\$ 0.87	0.70
New York Harbor 3-2-1 refinery crack spread – per bbl	US\$ 7.02	5.31
US\$ per Cdn\$ exchange rate	US\$ 0.768	0.714

OUTLOOK FOR BUSINESS ENVIRONMENT IN 2005

Prices for energy commodities are expected to remain volatile in 2005, reflecting the vagaries of weather, the changing level of industry inventories, and political and natural events. Slower global oil demand growth combined with non-OPEC production gains are expected to ease the upward pressure experienced by oil prices during 2004. The extent of the anticipated price correction depends on OPEC decisions on production cuts designed to prevent prices from declining as global demand conditions weaken.

The North American natural gas supply/demand balance is also expected to slacken in 2005. Little or no demand growth is forecast as a result of unseasonably warm winter weather and strong inter-fuel competition in the industrial and power generation sectors. These factors, combined with the industry's ability to slow anticipated production declines in North America, will maintain North American gas in storage at higher than historical levels. These dynamics are anticipated to relieve some of the upward pressure on natural gas prices experienced in 2004.

In the industry's downstream sector, refining margins are unlikely to remain at the high levels experienced in 2004. This is because refined product demand growth is expected to slow. Also, refineries are expected to rebuild product inventories as supply bottlenecks are dealt with and progress is made to meet mandated product specifications.

While volatility in the market will continue, a number of factors are expected to put downward pressure on strong crude oil and natural gas prices, as well as refining margins in 2005.

ECONOMIC SENSITIVITIES

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2004 net earnings, had these changes occurred. These calculations are based on business conditions, production and sales volumes realized in 2004.

Sensitivities Affecting Net Earnings

Factor ^{1,2}	Change (+)	Annual Net Earnings Impact (millions of dollars)	Annual Net Earnings Impact (\$ per share)
Upstream			
Price received for crude oil and liquids ³	\$1.00/bbl	45	0.17
Price received for natural gas	\$0.25/Mcf	33	0.12
Exchange rate: \$Cdn per \$US refers to impact on upstream earnings from operations	\$0.01	(22)	(0.08)
Crude oil and liquids production	1,000 b/d	5	0.02
Natural gas production	10 MMcf/d	9	0.03
Buzzard derivative contracts (unrealized) ⁴	\$1.00/bbl	(17)	(0.06)
Downstream			
New York Harbor 3-2-1 crack spread	\$0.10 US/bbl	4	0.02
Light/heavy crude price differential	\$1.00/bbl	11	0.04
Corporate			
Exchange rate: \$Cdn per \$US refers to impact of the revaluation of U.S. dollar-denominated, long-term debt ⁵	\$0.01	9	0.03

1 The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors.

2 The impact of these factors is illustrative.

3 This sensitivity is based upon an equivalent change in the price of WTI and North Sea Brent.

4 This refers to gains or losses on the forward sales contracts for the future sale of 35.8 million barrels of Brent crude oil that were entered into in connection with the Company's acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea.

5 This refers to gains or losses on \$869 million US of the Company's U.S. denominated long-term debt and interest costs on U.S. denominated debt. Gains or losses on \$1 billion US of the Company's U.S. denominated long-term debt, associated with the self-sustaining International business segment and the U.S. Rockies operations included in the North American Natural Gas business segment, are deferred and included as part of shareholders' equity.

Q:

What capabilities does Petro-Canada have that makes the Company confident it can execute its business strategy and differentiate itself from its peers?

A:

Petro-Canada has a unique breadth of skills due to its integrated portfolio of businesses. The Company continues to strengthen its capabilities through a focus on Q1 initiatives.

Internal Capabilities

As an integrated oil and gas company, Petro-Canada has a diverse set of skills and capabilities, the depth and breadth of which are somewhat unique for its size. To continue to improve and expand on this competitive advantage, the Company is committed to a Q1 (first quartile) mindset, action plans and performance measures. Petro-Canada defines Q1 as:

- improving operating performance to first quartile levels (top 25%) relative to benchmarked peers and best-in-class practices;
- efficiently using resources to manage controllable costs despite the growing complexity and scope of the business;
- seeking integration opportunities across businesses and functional areas for added value; and
- providing leadership which creates the work environment required for employees to excel.

Each of the businesses and Shared Services areas has Q1 action plans and performance measures. For example in East Coast Oil, a best practices initiative identifies process and technical opportunities to improve performance at Terra Nova. In the Downstream business, where the Q1 mindset originated, a scorecard is a key tool in maintaining employee focus on Q1 performance. Similar initiatives are also in the other business units.

The Finance unit was the first area of Shared Services to implement a Q1 initiative. The goal of this initiative is to be a value adding partner and trusted advisor for the business units and Shared Services units. In 2004, the Human Resources and Environment, Health and Safety units also started formal Q1 initiatives.

The Company recognizes it must continue to add breadth and depth of capability to sustain the base business and ensure profitable growth. To this end, the Human Resources Strategy addresses three key areas: effectively managing talent, improving human resources operational excellence, and supporting international and domestic business growth.

The Company's stated values are to be results-focused, decisive, trustworthy, professional and respectful. Petro-Canada believes it is important to build and maintain principle-based relationships with stakeholders. The Company works toward this goal with an active and ongoing stakeholder consultation process based on open, two-way communication with a genuine interest in understanding stakeholder interests and concerns.

This Q1 commitment, from improving capability to seeking integration opportunities, is embedded in Petro-Canada's business strategy.

Q:

What is Petro-Canada's business strategy?

A:

The Company's strategy is to create shareholder value by improving the profitability of the base business and by delivering long-term, profitable growth.

Business Strategy

The Company is improving the profitability of the base business by selecting the right assets and driving for Q1 performance. Long-term, profitable growth will be delivered by:

- expanding and exploiting the current portfolio of assets;
- targeting acquisitions and new opportunities with a focus on long-life assets; and
- developing an exploration program which balances risks and rewards to replace reserves over time.

In applying this strategy, Petro-Canada remains financially disciplined to retain the capacity and flexibility to sustain and grow the business.

In the upstream businesses, the Company believes it is unlikely rising North American demand for natural gas will be completely met through conventional production in the future. Petro-Canada is developing new sources of North American natural gas supply – unconventional gas, gas to fill the proposed northern pipelines and gas supplied through liquefied natural gas (LNG) technology. The East Coast Oil and Oil Sands businesses are also contributing volumes to meet North American demand. Petro-Canada is stepping out from established international platforms to access undeveloped reserves to supply growing global markets. In the Downstream business, the Company is leveraging the shift to cleaner fuels and a heavier oil supply by converting refineries to produce low-sulphur products from heavier crude slates and continuing to develop high-quality lubricants.

Petro-Canada's balanced portfolio provides opportunities for growth, a natural hedge against changing circumstances and integration among businesses for greater potential value. The Company applies its diverse set of internal skills to implement the business strategy.

Over time, the Company expects that the outcomes of implementing its business strategy will be:

- a continued focus on profitability;
- a shift to higher netback production;
- longer-life assets that will increase reserve life;
- a balanced exploration program;
- long-term upstream production growth; and
- a solid balance sheet with financial flexibility.

Risk Management

PETRO-CANADA'S RISK PROFILE

Petro-Canada's results are impacted by management's strategy for handling risks in the business. These risks fall into four broad categories: business risks; operational risks; political risks; and market risks.

Management believes each major risk requires a unique response based on Petro-Canada's business strategy and financial tolerance. While some risks can be effectively managed through internal controls and business processes, others are managed through insurance and hedging. The Audit, Finance and Risk Committee of the Board of Directors has responsibility to oversee risk management. The following describes Petro-Canada's approach to managing major risks.

BUSINESS RISKS

Exploration

Petro-Canada's future cash flows are highly dependent on the ability to offset natural declines as reserves are produced. Reserves can be added through successful exploration or acquisitions; however, as basins mature, replacement of reserves becomes more challenging and expensive. In some areas, the Company may choose to allow reserves to decline if replacement is uneconomic. In 2004, the Company replaced 96% of its production on a proved reserves basis, compared to 59% in 2003. The Company targets to fully replace proved reserves over a five-year period. Petro-Canada's five-year proved replacement ratio was 150%.¹

There is no assurance Petro-Canada will successfully replace all produced reserves in any given year.

Reserves Estimates

Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions that include geoscientific interpretation, commodity prices, operating and capital costs, and historical production from properties.

Petro-Canada has well-established, corporate-wide reserves booking practices that have been continuously improved for more than a decade. PricewaterhouseCoopers LLP, as contract internal auditor, has tested the non-engineering control processes used in establishing reserves. As well, independent engineering firms assess a significant portion of reserves estimates every year. Over time, this means all of Petro-Canada's reserves estimates are assessed by external evaluators. The Board of Directors also reviews and approves the Company's annual reserves filings. More information on reserves booking practices can be found in the Company's Annual Information Form.

Project Execution

Petro-Canada manages a number of different-sized projects to support continuing operations and future growth. Many projects are influenced by external factors beyond the Company's control. These include items such as material costs, labour productivity, timely availability of skilled labour and currency fluctuations.

While Petro-Canada cannot control all project inputs, the Company is committed to continuing to improve its project management capability. Petro-Canada's goal is to consistently and predictably deliver projects on time and on budget, and achieve defined expectations. Enhanced project management capability is expected to improve all elements of project execution including safety and environmental performance, quality, cycle-time and cost. Leveraging experience gained from major project developments, the Company established project management best practices.

¹ Proved reserves replacement ratio is calculated by dividing the year-over-year net change in proved reserves before deducting production by the annual production during the year. The reserves replacement ratio is a general indicator of the Company's reserves growth. It is only one of a number of metrics which can be used to analyze a company's upstream business.

Non-Operated Interests

Other companies may manage the construction or operation of assets in which Petro-Canada has a significant interest. Business assets in which Petro-Canada has a major interest, but does not operate, include Hibernia (20% interest), Syncrude (12% interest), White Rose (27.5%) and the newly acquired Buzzard (29.9% interest). Major projects are managed through different forms of joint-venture executive committees, resulting in Petro-Canada having some ability to influence these projects. As well, Petro-Canada has joint-venture or other operating agreements which specify its expectations from third-party operators. Nevertheless, third-party operation and management of the Company's assets could adversely affect Petro-Canada's financial performance.

Environmental Regulations

Environmental risks in the oil and gas industry are significant. This is because related laws and regulations are becoming more stringent in Canada, and in other countries where Petro-Canada operates. Due to increased regulations, Petro-Canada is investing additional capital to satisfy new product specifications and/or address environmental issues. In 2005, the Company will invest \$635 million of its capital program toward regulatory compliance, most of which will be to modify refineries to produce low-sulphur distillate. Other environmental regulations may result in future increased operating costs as a result of creating a future liability when dismantling or remediating assets.

Petro-Canada conducts Life-Cycle Value Assessments (LCVA) to integrate and balance environmental, social and economic decisions related to major projects. A key component of the LCVA process is to assess and plan for all life-cycle stages involved in constructing, manufacturing, distributing and eventually abandoning an asset or a product. This process encourages more comprehensive exploration of alternatives. The LCVA is a useful technique; however, its predictive capability is limited by the reliance on the current regulatory regime or one that can be reasonably expected.

Emission of Greenhouse Gases

The Kyoto Protocol, ratified by the Government of Canada in December 2002 and effective as of February 16, 2005, requires signatory nations to reduce their emissions of carbon dioxide and other greenhouse gases. As a result, Petro-Canada may be required to reduce emissions of greenhouse gases from operations or purchase emission trading credits. While the details of implementation of the Kyoto Protocol in Canada have not been finalized, the impact to Petro-Canada could be higher capital expenditures and operating expenses. The Government of Canada may also impose higher vehicle fuel efficiency standards. The impact of this action could be to decrease the demand for gasoline and diesel fuels sold by Petro-Canada and depress the Company's margins for refined products.

Petro-Canada is committed to reducing emissions. Additional detail will be available in the Report to the Community in the second quarter of 2005. The Report will be posted on www.petro-canada.ca. Through industry organizations, Petro-Canada continues to work with a number of regulatory groups and government associations to find a cost-effective approach which will minimize the negative financial impact of the Kyoto Protocol on the Company while still reducing emissions. The level of influence these discussions and cooperative efforts have on the Government of Canada's implementation plan may be quite limited.

Government Regulations

Petro-Canada's operations are regulated by, and could be intervened upon by, a variety of governments around the world. Governments could impact contracting of exploration and production interests, impose specific drilling obligations, and possibly expropriate or cancel contract rights. Governments may also regulate prices of commodities or refined products, or intervene through taxes, royalties and exploration rights.

Petro-Canada tries to mitigate the impact of government regulations by selecting operating environments with stable governments. To date, Petro-Canada has had a cooperative relationship with its regulators and the governments in the countries in which it operates. Most of the contact with regulators occurs through the Company's management, regulatory affairs personnel in each business unit and a centralized corporate government relations function. Petro-Canada aims to have regular, constructive communication with regulators and governments so issues can be resolved in a mutually acceptable fashion. The Company also has a strong record of regulatory compliance within the jurisdictions it operates. Petro-Canada operates in many different jurisdictions and derives revenue from several categories of products. This diversification makes financial performance less sensitive to the action of any single government. Nevertheless, Petro-Canada has limited ability to influence regulations which may have a material adverse effect on the Company.

Counterparties

In the normal course of business, Petro-Canada is exposed to credit risk resulting from the uncertainty of business partners' or counterparties' ability to fulfill their obligations. The Company has established internal credit policies and procedures that include financial assessments, exposure limits and processes to monitor and minimize the exposures against these limits. Where appropriate, Petro-Canada also uses netting and collateral arrangements to minimize risk.

OPERATIONAL RISKS

Exploring for, developing, producing, refining, transporting and marketing oil, natural gas and refined products involve significant operational hazards. These risks include well blowouts, fires, explosions, gaseous leaks, migration of harmful substances and oil spills. Any of these operational incidents could cause personal injury, environmental contamination, or damage and destruction of the Company's assets. These incidents could also interrupt production.

Petro-Canada manages operational risks primarily through a Total Loss Management (TLM) system and a corporate insurance program. TLM is an internally developed management system based on external best practices with standards for preventing operational incidents. Regular TLM audits test compliance with these standards. The corporate insurance program transfers the impact of some operational risks to third-party insurers worldwide. Petro-Canada optimizes the program by evaluating deductibles, limits and coverage. The Company's financial tolerance to withstand the impact of a major isolated event may be used to manage total premium cost. Although Petro-Canada maintains insurance in line with customary industry practices, the Company cannot fully insure against all risks. Losses resulting from operational incidents could have a material adverse impact on the Company.

POLITICAL RISKS

Petro-Canada operates in a number of countries that have varying political, economic and social systems. As a result, the Company's operations and related assets are subject to potential risks from actions by governmental authorities or internal unrest. Petro-Canada also operates in OPEC-member countries and production in those countries is constrained by OPEC quotas.

The Company continually evaluates exposure in any one country in the context of total operations. Investment may be limited to avoid excessive exposure in any one country or region. The Company also uses financial products to partially mitigate some political risks.

MARKET RISKS

More detailed quantification of the impact of some of the following risks can be found in the earnings sensitivity chart on page 4 of the Business Environment in the MD&A.

Commodity Prices

In Petro-Canada's upstream businesses, a significant market risk exposure is the changing commodity prices of crude oil and natural gas. Commodity prices are volatile and influenced by factors such as supply and demand fundamentals, geopolitical events, OPEC decisions and weather. In 2004, the monthly average Brent crude oil price ranged between \$30.83 US/bbl and \$49.64 US/bbl, and the AECO-C hub index ranged between \$5.93/Mcf and \$8.35/Mcf. These commodity prices also impact the refined products margins realized by the Downstream business, another significant market risk. In 2004, the benchmark monthly average New York Harbor 3-2-1 refinery crack spread per bbl ranged from \$4.23 US to \$11.41 US. Petro-Canada's ability to maintain product margins in an environment of higher feedstock costs is contingent upon the Company's ability to flow higher costs through to customers.

Petro-Canada generally does not hedge large volumes of production. Management believes commodity prices are volatile and difficult to predict. The business is managed so that the Company can substantially withstand the impact of a lower price environment, while maintaining the opportunity to capture significant upside when the price environment is higher. However, commodity prices and margins may be hedged occasionally to capture opportunities that represent extraordinary value and to ensure the economic value of an acquisition. For example, as part of the Company's acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea, the Company entered into a series of derivative contracts related to the future sale of Brent crude oil (see Derivative Instruments page 11 of the MD&A). Certain Downstream physical transactions are routinely hedged for operational needs and to facilitate sales to customers.

Foreign Exchange

As energy commodity prices are primarily priced in U.S. dollars, a large portion of Petro-Canada's revenue stream is affected by the Canada/U.S. exchange rate. As a result, the Company's earnings are negatively affected by a strengthening Canadian dollar. The Company is also exposed to fluctuations in other foreign currencies, such as the Euro and the British Pound.

Generally, Petro-Canada does not hedge foreign exchange exposures, although the Company partially mitigates the U.S. dollar exposure by denominating the majority of its debt obligations in U.S. dollars. Foreign exchange exposure related to asset acquisitions or divestitures, or project capital expenditures, may be hedged on a case-by-case basis.

Interest Rates

Petro-Canada targets a blend of fixed and floating rate debt. Generally, this enables the Company to take advantage of lower interest rates on floating debt, while matching overall debt maturities with the life of cash-generating assets. The Company is exposed to fluctuations in the rate of interest it pays on floating rate debt.

This interest rate exposure is within the Company's risk tolerance.

Derivative Instruments

Petro-Canada's Market Risk and Derivative policy prohibits the use of derivative instruments for speculative purposes. Petro-Canada uses derivatives primarily to hedge physical transactions for operational needs and to facilitate sales to customers. The gains and losses associated with these financial instruments essentially offset gains and losses on the physical transactions. Except as specifically authorized by the Board of Directors, the term of hedging instruments cannot exceed 18 months. Monitoring and reporting of the derivatives portfolio includes periodic testing of the fair value of all outstanding derivatives. Fair values are determined by obtaining independent third-party quotes for the value of each derivative instrument. The objectives and strategies of all hedge transactions are documented and the effectiveness of the derivative instrument in offsetting a change in the value of the hedged exposure is assessed on a regular basis.

Effective January 1, 2004, the Company elected to discontinue hedge accounting for certain hedging programs. All derivatives that do not qualify as a hedge, or are not designated as a hedge, are accounted for using the mark-to-market accounting method. These derivatives are recorded in the balance sheet as either an asset or liability, with the fair value recognized in earnings. As a result, the realized and unrealized values of these transactions are recognized in Investment and Other Income.

During 2004, as part of the Company's acquisition of an interest in the Buzzard field, the Company entered into a series of derivative contracts related to the future sale of Brent crude oil. The purpose of these transactions was to ensure value-adding returns to Petro-Canada on this investment, even in the event of a material decrease in oil prices. These contracts effectively lock in an average forward price of approximately \$26 US/bbl on a volume of 35,840,000 barrels. This volume represents approximately 50% of the Company's share of estimated plateau production in the 2007 to 2010 time frame. As at December 31, this hedge had a mark-to-market unrealized loss of \$205 million after-tax which was recognized in net earnings in 2004.

In 2004, other commodity hedges in place for refining supply and product purchases resulted in a net decrease in earnings of about \$1 million after-tax, which included a mark-to-market unrealized gain as at December 31 of \$3 million after-tax. This compared with a net decrease in earnings of about \$30 million in 2003, which related to commodity hedges, interest rate hedges and currency hedges.

Q:

What was Petro-Canada's financial performance in 2004?

A:

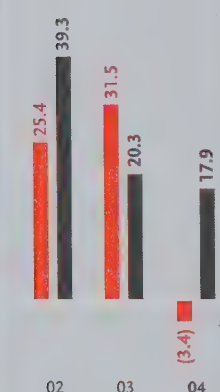
In 2004, Petro-Canada achieved record earnings from operations of \$1.9 billion and record cash flow of \$3.7 billion.

Consolidated Financial Results

ANALYSIS OF CONSOLIDATED EARNINGS AND CASH FLOW

Shareholder Value

Shareholder value measures the change in the Petro-Canada share price plus dividend returns.



■ One-year return (%)
■ Three-year average return (%)

Consolidated Financial Results

(millions of dollars, unless otherwise indicated)

	2004	2003	2002
Net earnings	\$ 1,757	\$ 1,650	\$ 955
Gain (loss) on foreign currency translation	63	239	(52)
Unrealized loss on Buzzard derivative contracts	(205)	—	—
Gain on sale of assets	11	29	2
Earnings from operations^{1,3}	\$ 1,888	\$ 1,382	\$ 1,005
Income tax adjustment	13	45	—
Edmonton refinery conversion provision	—	(82)	—
Kazakhstan impairment	—	(46)	—
International provisions	—	45	—
Oakville closure costs	(46)	(151)	—
Terra Nova insurance proceeds	31	17	—
Earnings from operations excluding adjustments for one-time and unusual items	\$ 1,890	\$ 1,554	\$ 1,005
Earnings per share (dollars) – basic	\$ 6.64	\$ 6.23	\$ 3.63
– diluted	6.55	6.16	3.59
Cash flow from operating activities			
before changes in non-cash working capital ^{2,3}	3,747	3,372	2,276
Cash flow from operating activities before changes in non-cash working capital per share (dollars)	14.16	12.73	8.66
Debt	2,580	2,229	3,057
Cash and cash equivalents	170	635	234
Average capital employed	\$ 10,533	\$ 9,268	\$ 7,722
Return on capital employed (%)	17.5	19.0	13.8
Operating return on capital employed (%)	18.8	16.1	14.5
Return on equity (%)	21.5	24.9	18.3

1 Earnings from operations, which represent net earnings excluding gains or losses on foreign currency translation and on disposal of assets and the unrealized gains or losses associated with the Buzzard derivative contracts, is used by the Company to evaluate operating performance.

2 Cash flow, which is expressed before changes in non-cash working capital items relating to operating activities, is used by the Company to analyze operating performance, leverage and liquidity.

3 Earnings from operations and cash flow do not have any standardized meaning prescribed by Canadian GAAP and, therefore, may not be comparable with the calculation of similar measures for other companies.

2004 COMPARED WITH 2003

Earnings from operations adjusted for one-time and unusual items rose 22% to \$1,890 million in 2004. Earnings were positively impacted by strong commodity prices and refining margins, as well as lower exploration expense and interest charges. These factors were partially offset by lower upstream volumes, higher operating costs and a stronger Canadian dollar.

In 2004, earnings from operations included a number of one-time and unusual items: a \$46 million charge for additional depreciation and other charges related to the consolidation of Eastern Canada refinery operations and the closure of the Oakville refinery; \$31 million of insurance proceeds related to the delayed start-up of Terra Nova; and a \$13 million positive adjustment to future income taxes reflecting announced changes to Canadian provincial income tax rates.

In 2003, earnings from operations included a number of one-time and unusual items: a \$151 million charge for additional depreciation and other charges related to the consolidation of Eastern Canada refinery operations and the closure of the Oakville refinery; an \$82 million charge related to the original conversion plan at the Edmonton refinery; a \$46 million provision related to the impairment of assets in Kazakhstan; a \$45 million positive adjustment in International related to the clarification of production rights and a tax provision of a former operation; a \$45 million net positive adjustment to future income taxes reflecting announced changes to Canadian federal and provincial income tax rates; and \$17 million of insurance proceeds related to the delayed start-up of Terra Nova.

Net earnings in 2004 were \$1,757 million, up 6% from \$1,650 million in 2003. Net earnings include gains or losses on foreign currency translation and on disposal of assets and an unrealized loss on Buzzard derivative contracts.

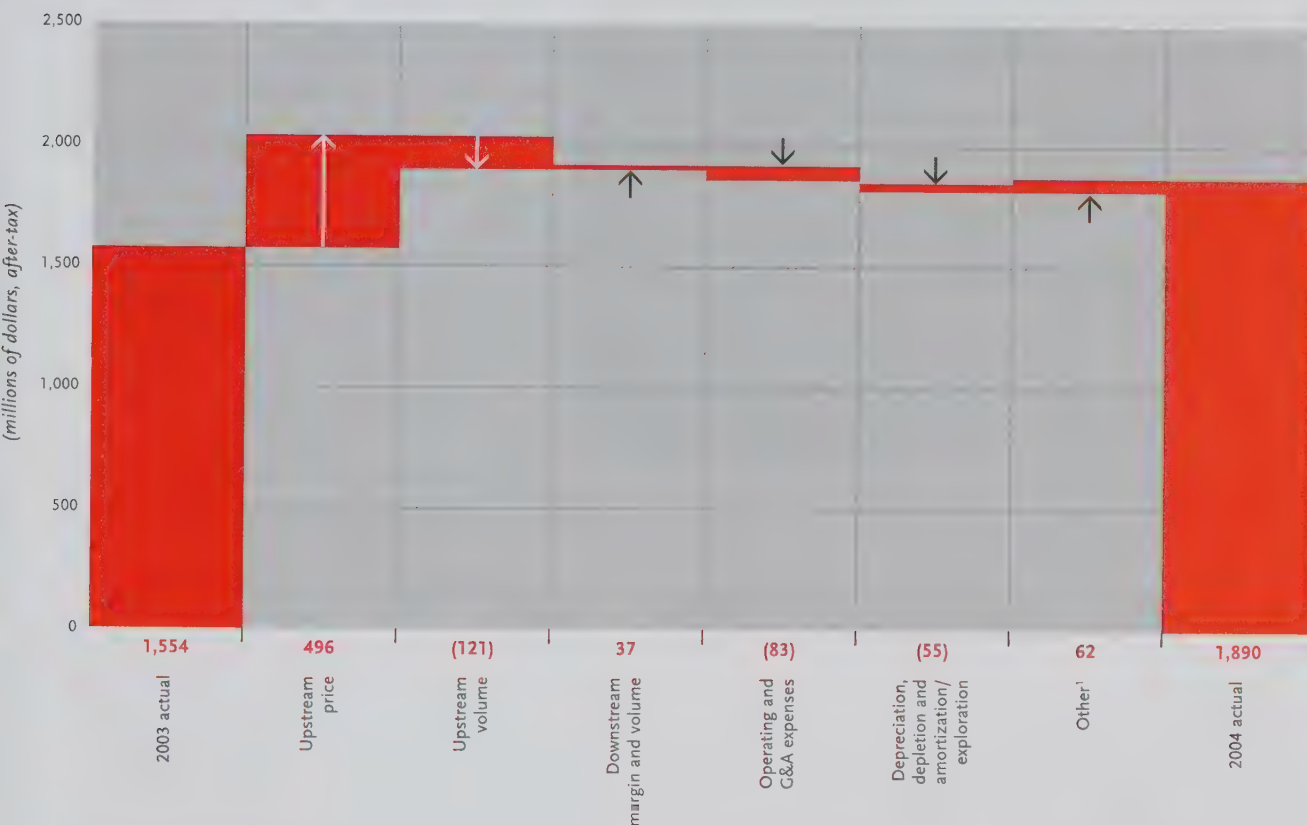
Operating Return on Capital Employed

Operating return on capital employed increased by 2.7% in 2004.



2004 VERSUS 2003 FACTOR ANALYSIS

Earnings from Operations Excluding Adjustments for One-time and Unusual Items



¹ Other mainly includes interest expense and changes in effective tax rates and upstream inventory levels.

Consolidated 2004 cash flow was \$3,747 million, compared with \$3,372 million in 2003. The increase in cash flow reflects higher earnings from operations partially offset by higher current income taxes.

QUARTERLY INFORMATION

Consolidated Quarterly Financial Results

(millions of dollars, unless otherwise indicated)

	2004				2003			
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Total revenue	\$ 3,473	\$ 3,565	\$ 3,622	\$ 3,717	\$ 3,722	\$ 2,957	\$ 3,118	\$ 3,102
Earnings from operations	517	471	461	439	485	451	296	150
Net earnings	513	393	410	441	579	584	289	198
Cash flow from operating activities before changes in non-cash working capital	921	885	895	1,046	991	874	879	628
Earnings per share (dollars)								
– basic	\$ 1.93	\$ 1.48	\$ 1.54	\$ 1.69	\$ 2.19	\$ 2.20	\$ 1.09	\$ 0.75
– diluted	\$ 1.90	\$ 1.46	\$ 1.52	\$ 1.67	\$ 2.16	\$ 2.17	\$ 1.08	\$ 0.74

Variances from quarter to quarter in revenues and net earnings resulted mainly from: fluctuations in commodity prices and refinery cracking margins; the impact on production and processed volumes from maintenance and other shutdowns at major facilities; and the level of exploration drilling activity. For further analysis of quarterly results, refer to Petro-Canada's quarterly reports to shareholders available on the Company's Web site at www.petro-canada.ca.

Q:

How does Petro-Canada manage its financial affairs?

A:

Petro-Canada maintains its financial strength and flexibility by targeting its debt levels at 25% to 35% of total capital and a ratio of less than 2.0 times debt to cash flow.

Liquidity and Capital Resources

Summary of Cash Flows

(millions of dollars)

	2004	2003	2002
Net cash inflows (outflows) before changes in non-cash working capital:			
Operating activities	\$ 3,747	\$ 3,372	\$ 2,276
Investing activities	(4,709)	(2,297)	(4,141)
Financing activities	(19)	(604)	1,560
	(981)	471	(305)
(Increase) decrease in non-cash working capital and other	516	(70)	(242)
Increase (decrease) in cash and cash equivalents	\$ (465)	\$ 401	\$ (547)
Cash and cash equivalents at end of year	\$ 170	\$ 635	\$ 234

The Company maintains solid investment-grade credit ratings.

The improvement in cash flow before changes in non-cash working capital to \$3,747 million in 2004 was primarily from higher earnings from operations partially offset by higher current taxes. The increased cash outflow on investing activities reflected the Buzzard and U.S. Rockies acquisitions. The \$117 million decrease in non-cash working capital reflected higher accounts payable and accrued liabilities along with income taxes payable, partially offset by higher accounts receivable.

INVESTING ACTIVITIES

Capital and Exploration Expenditures

	2005 Outlook	2004	2003	2002
<i>(millions of dollars)</i>				
Upstream¹				
North American Natural Gas	\$ 760	\$ 724	\$ 560	\$ 530
East Coast Oil	315	278	344	289
Oil Sands	400	399	448	462
International	825	1,824 ²	525	221
	2,300	3,225	1,877	1,502
Downstream				
Refining and Supply	780	656	296	210
Sales and Marketing	105	171	117	118
Lubricants	35	12	11	16
	920	839	424	344
Shared Services	15	9	14	15
Total property, plant and equipment and exploration	3,235	4,073	2,315	1,861
Deferred charges and other assets	—	36	147	72
Acquisition of oil and gas operations of Veba Oil & Gas GmbH (Veba)	—	—	—	2,234
Acquisition of Prima Energy Corporation	—	644	—	—
Total	\$ 3,235	\$ 4,753	\$ 2,462	\$ 4,167

1 Includes exploration expenses charged to earnings, totaling \$235 million in 2004, \$271 million in 2003 and \$301 million in 2002.

2 Includes \$1,218 million for the Buzzard acquisition.

Capital spending on property, plant and equipment and exploration in 2004 reflected Petro-Canada's commitment to long-term profitable growth and adding value for shareholders. The 76% increase in expenditures to \$4,073 million, up from \$2,315 million in 2003, was mainly due to the Buzzard acquisition and costs associated with the development of the Buzzard project, the investments related to upgrading refineries to produce cleaner-burning fuels, increased spending for the pursuit of attractive opportunities in Western Canada and the acceleration of the Company's retail re-imaging program.

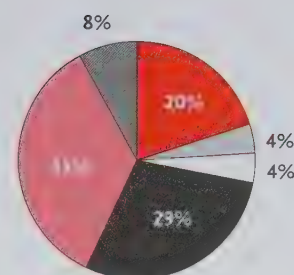
Planned investment for 2005, totaling \$3,235 million, reflects a "building year" for Petro-Canada. The focus on growth initiatives is expected to deliver new production in 2006 and 2007. The 2005 capital expenditure program is expected to be funded from cash flow and existing credit facilities.

FINANCING ACTIVITIES AND DIVIDENDS

Financial Ratios

	2004	2003	2002
<i>(times)</i>			
Interest coverage			
Earnings basis	20.9	16.6	10.4
EBITDAX basis	31.0	26.3	17.1
Cash flow basis	33.0	25.4	17.9
Debt to cash flow	0.7	0.7	1.3
Debt-to-debt plus equity (%)	22.8	22.7	35.1

Petro-Canada's debt to cash flow ratio, the key short-term leverage measure, was 0.7 times as of December 31, 2004, unchanged compared to the prior year. The Company expects to remain well within the target range of no more than 2.0 times throughout 2005. Debt-to-debt plus equity, the long-term measure for capital structure, was 22.8% at year-end 2004, up slightly from 22.7% at the prior year end. This is well within the target range of 25% to 35%. Petro-Canada has controls in place to ensure compliance with all financial covenants.



2005 Capital Program

(millions of dollars)

Capital program by investment priority:

- Regulatory compliance: **635**
- Enhancing existing assets: **130**
- Improving base business profitability: **120**
- Reserves replacement in core areas: **950**
- New growth projects: **1,130**
- Exploration and new ventures: **270**

Key debt ratios have remained relatively unchanged from 2003 levels notwithstanding the significant investment program in 2004.

Interest Coverage

The Company's positive interest coverage ratio demonstrates more than sufficient earnings to cover interest charges on debt.



Sources of Capital Employed

(millions of dollars)

	2004	2003	2002
Short-term notes payable	\$ 299	\$ —	\$ —
Long-term debt, including current portion	2,281	2,229	3,057
Shareholders' equity	8,739	7,588	5,662
Total	\$ 11,319	\$ 9,817	\$ 8,719

Total debt increased to \$2,580 million at December 31, 2004, compared with \$2,229 million at the previous year end. The increase in debt was associated with the activities outlined in the financing activities section and general operating needs, offset by a reduction of \$182 million due to revaluation of the U.S. dollar-denominated long-term debt. Short-term notes payable consisted of \$70 million of U.S. dollar-denominated Canadian commercial paper and \$215 million in Canadian dollar-denominated Canadian commercial paper.

2004 Financing Activities

Petro-Canada's balance sheet was put to use in support of business growth initiatives in 2004. During the second quarter, the Company borrowed \$210 million US under the syndicated operating credit facilities to partially fund the acquisition of a 29.9% interest in the Buzzard oilfield. The balance of the \$887 million US acquisition cost was funded with existing cash balances. All advances under the syndicated operating credit facilities were repaid in the third quarter.

During the third quarter, the Company borrowed \$400 million US under an acquisition credit facility to acquire all of the outstanding shares of Prima Energy Corporation (referred to as the U.S. Rockies). The remainder of the total acquisition price of \$644 million, net of acquired cash, was funded using cash on hand and short-term borrowings.

In the fourth quarter of 2004, the Company issued \$400 million US of 10-year senior notes. The net proceeds were used to repay the U.S. Rockies acquisition credit facility.

Also during the year, Petro-Canada sold \$400 million under a new accounts receivable securitization program. A portion of the proceeds was used to repay the remaining \$293 million of advances under the acquisition credit facility that funded the purchase of Veba in 2002.

In addition to financing growth, the Company also had the capacity to create value by returning capital to shareholders during the year. The TSX approved Petro-Canada's application to make a normal course issuer bid for the repurchase of up to 21 million of its common shares over the 12-month period ending June 21, 2005, subject to certain conditions. By year-end 2004, the Company had repurchased and cancelled a total of 6,868,082 shares at an average price of \$65.02 per share for a total cost of approximately \$447 million. Petro-Canada intends to continue to repurchase shares when there is an opportunity to create value.

For operating purposes, Petro-Canada had cash and cash equivalents of \$170 million at year-end 2004. During 2004, the Company put in place new syndicated operating credit facilities totaling \$1,500 million to be used for general corporate purposes. There were no draws on these facilities at year end; however, they provide liquidity support to Petro-Canada's Canadian commercial paper program. The Company will continue to use its cash position and will draw on bank lines and issue commercial paper, as necessary, to meet working capital and other financing requirements.

Petro-Canada plans to meet remaining debt repayment commitments out of a combination of cash flow and debt refinancing.

At year-end 2004, the Company's unsecured long-term debt securities were rated Baa2 by Moody's Investors Services, BBB by Standard & Poor's Rating Services and A (low) by Dominion Bond Rating Service. These ratings remained unchanged from year-end 2003.

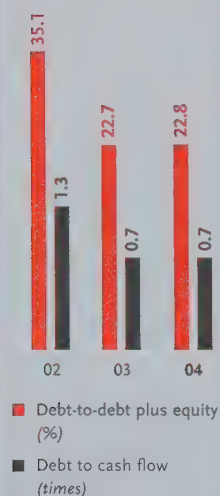
Excluding cash and cash equivalents, short-term notes payable and the current portion of long-term debt, Petro-Canada had an operating working capital deficiency of \$777 million as at December 31, 2004, compared with an operating working capital deficiency of \$52 million at the end of 2003. The working capital deficiency increase was primarily due to the accounts receivable securitization program and higher accounts payable resulting from higher commodity prices and capital accruals.

Off-balance sheet activities are limited to matters such as the accounts receivable securitization program, which does not meet the criteria for consolidation and guarantees. None of these would have a material impact on the Company's financial results, liquidity or capital resources.

At year-end 2004, Petro-Canada's defined benefits pension plans were under-funded by \$330 million, compared with an under-funded position of \$292 million at year-end 2003. In 2004, Petro-Canada made

Key Debt Ratios

Petro-Canada has the financial strength and flexibility to manage changing market dynamics and pursue new growth opportunities.



cash contributions of \$93 million to the pension plans and recorded a pension expense of \$71 million before tax. This compares with \$86 million of cash contributions and \$72 million of pension expense, respectively, for 2003. In 2005, the Company expects to make pension contributions of approximately \$95 million.

The following table summarizes Petro-Canada's contractual obligations as at December 31, 2004.

Contractual Obligations – Summary

(millions of dollars)

		PAYMENTS DUE BY PERIOD			
	Total	2005	2006-2007	2008-2009	2010 and thereafter
Unsecured debentures and senior notes ¹	\$ 4,774	\$ 137	\$ 277	\$ 277	\$ 4,083
Short-term notes payable ¹	299	299	—	—	—
Capital lease obligations ¹	178	17	34	21	106
Operating leases	650	122	182	129	217
Transportation agreements	1,302	198	329	256	519
Product purchase/delivery obligations ²	1,561	83	234	172	1,072
Exploration work commitments ³	119	60	53	6	—
Asset retirement obligations	2,417	72	126	55	2,164
Other long-term obligations ^{4,5}	2,059	123	7	154	1,775
Total contractual obligations	\$ 13,360	\$ 1,111	\$ 1,242	\$ 1,070	\$ 9,936

1 Obligations include related interest. For further details see Note 17 to the 2004 Consolidated Financial Statements.

2 Excludes supply purchase agreements contracted at market prices, where the products could reasonably be re-sold into the market.

3 Excludes other amounts related to the Company's expected future capital spending. Capital spending plans are reviewed and revised annually to reflect Petro-Canada's strategy, operating performance and economic conditions. For further information regarding future capital spending plans refer to the business segment and investing activities discussions in the sections of the 2004 MD&A.

4 Includes processing agreement with Suncor Energy Inc., receivables securitization program, pension funding obligations for the periods prior to the Company's next required pension plan valuation and other obligations. Pension obligations beyond the next required pension valuation date were excluded due to the uncertainty as to the amount or timing of these obligations.

5 Petro-Canada is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company. The table excludes amounts for these contingencies due to the uncertainty as to the amount or timing of any settlements.

During 2004, Petro-Canada's total contractual obligations increased by approximately \$7,700 million, mainly due to finalization of an agreement with Suncor Energy Inc. for the processing of future bitumen production, an increase in debt levels associated with the U.S. Rockies acquisition, obligations relating to the accounts receivable securitization and the inclusion of obligations relating to interest and asset retirements, which were previously excluded.

Dividend Strategy

From time to time, Petro-Canada reviews its dividend strategy to ensure the alignment of dividend policy with shareholder expectations and financial and growth objectives. Currently, the Company's first priority for available cash is to fund profitable growth opportunities. The second priority is to return funds to shareholders through dividends and share buyback programs. Commencing with the second quarter dividend paid on April 1, 2004, the Company increased the quarterly dividend 50% to \$0.15 per share. Total dividends paid in 2004 were \$159 million, compared with \$106 million in 2003.

Petro-Canada increased its dividend by 50% in 2004.

Government Public Offering

In September 2004, the Government of Canada completed the public offering of its remaining 19% interest in the Company. The government sold approximately 49 million Petro-Canada common shares at a price of \$64.50 per share, resulting in total gross proceeds to the government of approximately \$3.2 billion.

UPSTREAM

Petro-Canada's upstream operations consist of four business segments: North American Natural Gas, with current production in Western Canada and the U.S. Rockies; East Coast Oil, with three major developments offshore Newfoundland and Labrador; Oil Sands operations in Northeastern Alberta; and International, where the Company is active in three core areas: Northwest Europe; North Africa/Near East; and Northern Latin America. The diverse asset base provides a balanced portfolio and a platform for long-term growth.

Q:

How is Petro-Canada going to profitably replace North American Natural Gas production?

A:

Our plans include continuing the exploitation of our conventional assets, stepping out to unconventional production, advancing our liquefied natural gas (LNG) strategy and developing the frontier regions.

The Hanlan Robb natural gas plant in the Foothills region of Alberta.



The Wildcat Hills natural gas plant.

North American Natural Gas

BUSINESS SUMMARY AND STRATEGY

North American Natural Gas has a long history of exploring for and producing natural gas, crude oil and natural gas liquids in Western Canada. This business also markets natural gas in North America, has established resources in the Mackenzie Delta/Corridor and has landholdings in Alaska. In 2004, the business expanded into unconventional production and signed an agreement to develop a proposed LNG re-gasification facility in Quebec.

The North American Natural Gas strategy is to be a significant and sustainable market participant by accessing new and diverse natural gas supply sources in North America. Key features of the strategy include:

- continuing exploration and development in existing Western Canada conventional areas;
- increasing focus on unconventional production in the U.S. Rockies and Western Canada;
- developing LNG import capacity in North America; and
- building the northern resource base for long-term growth.

North American Natural Gas Financial Results

(millions of dollars)

	2004	2003	2002
Net earnings	\$ 500	\$ 492	\$ 168
Gain (loss) on sale of assets	—	33	(1)
Earnings from operations	\$ 500	\$ 459	\$ 169
Income tax adjustment	7	10	—
Earnings from operations excluding adjustments for one-time and unusual items	\$ 493	\$ 449	\$ 169
Cash flow from operating activities before changes in non-cash working capital	\$ 940	\$ 985	\$ 534
Expenditures on property, plant and equipment and exploration	\$ 724	\$ 560	\$ 530
Total assets	\$ 3,477	\$ 2,341	\$ 2,285

2004 COMPARED WITH 2003

North American Natural Gas contributed earnings from operations adjusted for one-time and unusual items of \$493 million in 2004, up 10% from \$449 million in 2003. The increase was largely driven by strong realized natural gas prices and acquired volumes from the U.S. Rockies. These factors were partially offset by lower Western Canada volumes and higher costs.

Net earnings from North American Natural Gas were \$500 million in 2004, up from \$492 million in 2003. Net earnings in 2004 included a \$7 million positive adjustment to reflect a reduction in provincial income tax rates. Net earnings in 2003 included a \$33 million after-tax gain on the sale of assets and a \$10 million positive adjustment to reflect the changes in federal and provincial tax rates.

Natural gas commodity prices and volumes remained strong in 2004. The realized natural gas price averaged \$6.72/Mcf, up 3% from \$6.50/Mcf in 2003. Natural gas production averaged 695 MMcf/d in 2004, up from 693 MMcf/d in 2003, as acquired volumes from the U.S. Rockies offset lower volumes in Western Canada. Conventional crude oil and natural gas liquids production averaged 15,300 b/d, down from 16,900 b/d in 2003 due to the disposition of properties in 2003.

2004 Operating Review and Strategic Initiatives

North American Natural Gas recorded solid operating results in 2004 from core areas in Western Canada and the U.S. Rockies. In addition, Petro-Canada announced a proposal to jointly develop an LNG re-gasification facility in Quebec and continued building its resource position in the Far North.

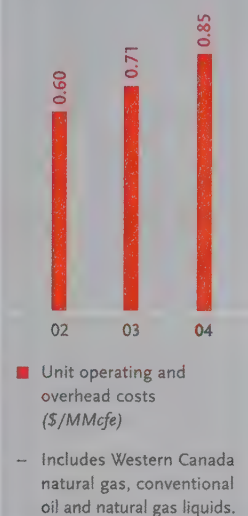
Western Canada continued to exploit conventional gas opportunities in four core areas – the Alberta Foothills, Northeastern British Columbia, Southeastern Alberta and West-Central Alberta. Western Canada natural gas production averaged 676 MMcf/d, down 2% from 693 MMcf/d in 2003. Exploration and development drilling activity in Western Canada resulted in 564 gross successful wells, for a success rate of 96% in 2004. Western Canada operating and overhead costs were \$0.85 per thousand cubic feet of natural gas equivalent (Mcf) in 2004, up from \$0.71/Mcf in the previous year. This increase reflected industry-wide cost increases and higher turnaround costs.

During 2004, the North American Natural Gas business grew to include unconventional gas operations and skills. In mid-2004, its footprint was extended into the U.S. Rockies by acquiring Prima Energy Corporation (U.S. Rockies) for \$644 million, net of acquired cash. This acquisition added 55 MMcf/d primarily from coal bed methane in the Powder River Basin and from tight gas in the Denver-Julesburg basin and significant expertise in unconventional production. The integration of this acquisition went smoothly in 2004.

In Western Canada, the business unit also began pursuing unconventional production. A dedicated team began developing tight gas opportunities east of the Foothills of Alberta and in Northeast British Columbia. During 2004, 20 gross wells were drilled and approximately 70,000 gross acres of land were acquired.

Western Canada Operating and Overhead Costs

Western Canada operating and overhead costs were largely driven by industry-wide cost increases, lower volumes and higher turnaround costs.



The U.S. Rockies acquisition in 2004 provided expertise and growth opportunities in unconventional gas.

North American
Natural Gas Annual
Production



Crude Oil and Natural
Gas Liquids Annual
Production



Petro-Canada will continue to access new supply from three sources: unconventional gas; Far North gas; and LNG projects.

Petro-Canada is seeking to participate in the global LNG business with the objective to add long-life producing assets to its portfolio. In September 2004, a Memorandum of Understanding (MOU) was signed with TransCanada PipeLines Limited to develop and share (50/50) ownership of a \$660 million LNG facility at Gros-Cacouna, Quebec. The proposed facility, targeted to be in service by late 2009, will receive, store and re-gasify imported LNG. Petro-Canada will have 100% of the send-out capacity of approximately 500 MMcf of natural gas per day.

Petro-Canada also continued to position itself for long-term North American supply by accessing Far North supply regions in advance of proposed northern pipeline projects. In the Mackenzie Delta/Corridor region, plans for development of existing discoveries of Tuk in the Mackenzie Delta and Tweed Lake and Bele in the Colville area were advanced. The business also purchased an exploration licence to add to its land base in the Corridor. In addition, a large land position was acquired in the National Petroleum Reserve-Alaska, an area with significant potential for large oil prospects.

Capital expenditures in 2004 totaled \$724 million, with \$625 million for exploration and development of natural gas in Western Canada, \$26 million for U.S. Rockies development and \$73 million for other natural gas opportunities in North America.

OUTLOOK

Production expectations in 2005:

- Western Canada production to average 630 MMcf/d of natural gas and 12,000 b/d of crude oil and natural gas liquids;
- U.S. Rockies production to average about 55 MMcf/d.

Action plans:

- drill approximately 650 gross wells in Western Canada in 2005;
- advance long-term opportunities in Northern Canada and Alaska;
- file regulatory application for LNG facility at Gros-Cacouna by mid-2005;
- double U.S. Rockies gas production by 2007.

Capital spending plans in 2005:

- \$485 million to replace reserves in the Western Canada core areas;
- \$230 million for new unconventional growth opportunities in Western Canada and the U.S. Rockies;
- \$45 million to develop long-term supply opportunities in Alaska and the Mackenzie Delta/Corridor, and to further the proposed Gros-Cacouna LNG re-gasification terminal.

The 2005 capital program of approximately \$760 million reflects a focus on replacing reserves in core areas and continuing to develop tight gas and coal bed methane production capability. Additional volumes from the U.S. Rockies are expected to largely offset, in the medium term, the natural declines of Western Canada conventional natural gas production. In the long term, supply from the Mackenzie Delta/Corridor, Alaska and LNG projects is expected to play a growing role to meet North American demand.

Western Canada will continue to exploit core conventional areas. In the Foothills, the business will capitalize on a strong technical and operating competency in deep sour gas and is well positioned with its producing infrastructure.

In the shallow gas region of Southeastern Alberta, production has steadily increased over the last few years to 78 MMcf/d at 2004 year end. This success is expected to continue as a result of a multi-year drilling program aimed at doubling well space density from four to eight wells per section. In Northeastern British Columbia, the business will continue to optimize and selectively explore existing assets. In the West Central region, declines will be managed through asset optimization and cost discipline.

In 2005, Western Canada intends to continue to pursue tight gas structures, with plans to drill approximately 35 additional wells. The full value from the U.S. Rockies acquisition will come from developing the large inventory of probable reserves. Petro-Canada plans to double unconventional gas equivalent production to 100 MMcf/d by 2007.

Q:

How is Petro-Canada going to sustain reliable and profitable East Coast production from these capital-intensive investments into the next decade?

A:

We have plans in place to achieve first quartile performance at existing platforms, add production through development of reservoir extensions, participate in White Rose and pursue new projects.

The Petro-Canada operated Terra Nova FPSO produces oil on the Grand Banks offshore Newfoundland and Labrador.



Workers on a support vessel prepare to tow an iceberg offshore Newfoundland and Labrador as part of the active ice management program.

East Coast Oil

BUSINESS SUMMARY AND STRATEGY

Petro-Canada is positioned in every major oil development off Canada's East Coast. The Company is the operator and holds the largest interest in Terra Nova (34%), and has a 20% interest in Hibernia, the first Grand Banks development. Petro-Canada also holds a 27.5% interest in the White Rose project, scheduled to be on-stream in 2006.

The East Coast Oil strategy is to improve reliability and sustain profitable production well into the next decade. Key features of the strategy include:

- delivering top quartile safety and operating performance;
- sustaining profitable production through reservoir extensions and add-ons; and
- pursuing high potential development projects.

East Coast Oil Operating and Overhead Costs

Operating and overhead costs are effectively unchanged in 2004.



White Rose will add approximately 25,000 b/d of production at plateau.

Petro-Canada's Share of Hibernia and Terra Nova Production



East Coast Oil Financial Results

(millions of dollars)

	2004	2003	2002
Net earnings and earnings from operations	\$ 711	\$ 597	\$ 428
Income tax adjustment	3	7	—
Terra Nova insurance proceeds	31	17	—
Earnings from operations excluding adjustments for one-time and unusual items	\$ 677	\$ 573	\$ 428
Cash flow from operating activities before changes in non-cash working capital	\$ 996	\$ 869	\$ 687
Expenditures on property, plant and equipment and exploration	\$ 278	\$ 344	\$ 289
Total assets	\$ 2,265	\$ 2,288	\$ 2,249

2004 COMPARED WITH 2003

East Coast Oil contributed earnings from operations adjusted for one-time and unusual items of \$677 million in 2004, up 18% from \$573 million in 2003. The earnings increase reflected higher realized prices, partially offset by lower production.

Net earnings from East Coast Oil were \$711 million in 2004, up from \$597 million in 2003. Net earnings in 2004 included a \$3 million positive adjustment to reflect a reduction in provincial income tax rates and \$31 million of insurance proceeds related to the delayed start-up of Terra Nova. Net earnings in 2003 included a \$7 million positive adjustment to reflect the changes in federal and provincial tax rates and \$17 million of insurance proceeds related to the delayed start-up of Terra Nova.

East Coast Oil realized crude prices averaged \$48.39/bbl, up from \$39.91/bbl in 2003.

Petro-Canada's share of East Coast Oil production averaged 78,200 b/d, down from 86,100 b/d in 2003. The decrease was largely due to lower production at Terra Nova.

East Coast Oil operating and overhead costs averaged \$2.89/bbl in 2004, effectively unchanged from \$2.88/bbl in 2003.

2004 Operating Review and Strategic Initiatives

Petro-Canada's share of Hibernia's production averaged 40,800 b/d in 2004, up from 40,600 b/d in 2003. The Hibernia platform continued to deliver first quartile operating performance. As a result of better-than-expected reservoir performance, the life of field reserves estimate increased from 835 MMbbls at year-end 2003 to 940 MMbbls at year-end 2004 at Hibernia, with Petro-Canada's share being 20%.

At Terra Nova, the Company's share of production averaged 37,400 b/d, down from 45,500 b/d in 2003. Both production and reliability measures were significantly below target due to extended maintenance activities and operating difficulties in the third and fourth quarters of 2004. During the third quarter, volumes were impacted by a longer-than-expected turnaround for repairs to the gas compression facilities. Further downtime occurred in the fourth quarter for investigation and repairs following a discharge of oily water. Following successful maintenance activities, production rates were returned to normal levels during the last half of December. Terra Nova reached simple royalty payout in 2004. Meeting this milestone in two-and-a-half years is a good indication of the value created by this asset.

The next East Coast development to come on-stream will be White Rose in early 2006, which will add approximately 25,000 b/d of production. The project remained on budget and on schedule in 2004, and key project milestones included: arrival of the Sea Rose Floating Production, Storage and Offloading (FPSO) hull in Newfoundland and Labrador; fabrication and lifting of the topsides modules onto the hull of the FPSO; initiation of the marine construction program offshore; and drilling of the first five development wells with pre-commissioning activities under way.

In 2004, capital expenditures for exploration and development of crude oil offshore Canada's East Coast were \$278 million, including \$155 million related to the development of the White Rose oilfield.

OUTLOOK

Production expectations in 2005:

- East Coast Oil production is expected to average 77,000 b/d, reflecting planned turnarounds.

Growth plans:

- achieve first quartile operating performance at Terra Nova;
- begin development drilling of Terra Nova's Far East block;
- submit development plans for Hibernia's Ben Nevis Avalon formation;
- complete White Rose development for early 2006;
- continue discussions on a Joint Operating Agreement with the partners of the potential Hebron project.

Capital spending plans in 2005:

- Approximately \$125 million will be spent on drilling to replace reserves at Hibernia and Terra Nova, and developing Terra Nova's Far East block and the Ben Nevis Avalon reservoir at Hibernia.
- Approximately \$190 million will be spent to bring the White Rose project on-stream in early 2006, adding 25,000 b/d net to Petro-Canada at peak production.

From a reliability perspective, Petro-Canada plans to achieve first quartile reliability and operating costs at Terra Nova during 2006. In 2005, a four-week planned turnaround will perform regulatory inspections on equipment and do work to improve the reliability of the gas compression and injection systems. These areas were the main cause of downtime over the past couple of years. The Hibernia platform will also have a one-week turnaround in 2005.

While royalty rates at Hibernia remained relatively constant in 2004, Terra Nova royalty rates increased to 5% in mid-2004 due to the simple royalty payout achieved. Further increases in royalty rates will occur in line with the project's profitability-sensitive royalty regime. Terra Nova royalties are forecast to average about 12% in 2005.

The business will continue development drilling in the main fields, with plans to bring on the Far East block at Terra Nova and to expand production from the Ben Nevis Avalon reservoir at Hibernia. East Coast Oil volumes are expected to increase in the second quarter of 2006, as production from the White Rose development comes on-stream. This production will help offset declines in the main reservoirs at Hibernia and Terra Nova.

Petro-Canada is also continuing to have discussions with partners on the potential Hebron project.

In East Coast Oil, the priorities are to improve reliability at Terra Nova and sustain profitable production while progressing the White Rose project.

Q:

Is Petro-Canada's phased and integrated strategy in the Oil Sands yielding results?

A:

We have made great strides to improve reliability. We see greater potential from these long-life assets as we integrate with our Edmonton refinery and bring on the next phase of oil sands development.

This production well at MacKay River collects heated bitumen, which is then piped to the site's central processing facility.



The steam from these four generators is used to reduce the viscosity of the tar-like bitumen so it can be brought to the surface.

Oil Sands

BUSINESS SUMMARY AND STRATEGY

Petro-Canada's major Oil Sands interests include a 12% ownership in the Syncrude joint venture (an oil sands mining operation and upgrading facility), 100% ownership of the MacKay River *in situ* bitumen development (a steam-assisted gravity drainage (SAGD) operation), a 60% ownership in and operator of the Fort Hills oil sands mining project and extensive oil sands acreage considered prospective for *in situ* development of bitumen resources.

The Oil Sands strategy for profitable growth includes:

- phased and integrated development of reserves to incorporate knowledge gained;
- disciplined capital investment to ensure long-life projects are value creating; and
- a staged approach to development of capital-intensive Oil Sands projects to allow rigorous cost management and the opportunity to benefit from evolving technology.

Oil Sands Financial Results

(millions of dollars)

	2004	2003	2002
Net earnings and earnings (loss) from operations	\$ 120	\$ (52)	\$ 78
Income tax adjustment	2	5	—
Edmonton refinery conversion program	—	(82)	—
Earnings from operations excluding adjustments for one-time and unusual items	\$ 118	\$ 25	\$ 78
Cash flow from operating activities before changes in non-cash working capital	\$ 334	\$ 127	\$ 196
Expenditures on property, plant and equipment and exploration	\$ 399	\$ 448	\$ 462
Total assets	\$ 1,883	\$ 1,770	\$ 1,498

2004 COMPARED WITH 2003

Oil Sands contributed earnings from operations adjusted for one-time and unusual items of \$118 million in 2004, up 372% from \$25 million in 2003. The earnings increase reflected higher realized prices and production at Syncrude and MacKay River in 2004.

Net earnings from Oil Sands were \$120 million in 2004, up from a net loss of \$52 million in 2003. Net earnings in 2004 included a \$2 million positive adjustment to reflect a reduction in provincial income tax rates. Net earnings in 2003 included a \$5 million positive adjustment to reflect changes in federal and provincial tax rates and an after-tax charge of \$82 million for the write-off of costs related to the original Edmonton refinery conversion plan.

At Syncrude, the average price realized for synthetic crude oil production in 2004 was \$52.40/bbl, up from \$42.67/bbl in 2003.

MacKay River realized prices for bitumen averaged \$18.37/bbl for 2004, up from \$16.69/bbl in 2003. Bitumen prices sank to extremely low levels in late 2004. This was due to the widening of light/heavy crude price differentials, to unprecedented levels, which hindered Oil Sands earnings. Operating costs averaged \$20.98/bbl in 2004, compared to \$22.11/bbl in 2003. Contributing factors to high operating costs were lower-than-expected volumes, increased water treatment costs and fixed contractual obligations.

Oil Sands production in 2004 averaged 45,200 b/d, up from 36,100 b/d in 2003, reflecting higher production at both Syncrude and MacKay River.

2004 Operating Review and Strategic Initiatives

A key focus for Oil Sands during 2004 was reliability.

At Syncrude, efforts to improve reliability and lower unit operating costs resulted in record gross production of 238,000 b/d. Syncrude also lowered unit operating costs by \$2.51/bbl. Average unit operating costs decreased to \$21.13/bbl in 2004, compared to \$23.64/bbl in 2003 due to improved reliability and higher volumes. Petro-Canada's share of Syncrude's production averaged 28,600 b/d, up from 25,400 b/d in 2003.

Capital expenditures for Syncrude in 2004 were \$314 million, mainly for the Stage III expansion. This project includes a second Aurora mine and an upgrading expansion. Construction progress and costs remain in line with the revised plan announced in March 2004, with completion scheduled for mid-2006.

MacKay River improved reliability of operations and production during 2004, but fell short of full year expectations of 25,000 b/d. In 2004, MacKay River production averaged 16,600 b/d, compared to 10,700 b/d in 2003. Continual improvements resulted in fourth quarter production averaging 19,800 b/d, compared to 16,300 b/d in the same period in 2003. Production was impacted by a one-week outage and subsequent ramp up resulting from a mechanical problem with the plant. There were also steam limitations when the third-party co-generation facility was not operational due to water treatment reliability. Reliability improved with steady operations from the 165-megawatt co-generation facility for the second half of 2004. Equipment to improve water treatment and plant reliability was successfully tied-in during the planned turnaround in the third quarter.

In 2004, capital expenditures were \$45 million for MacKay River and \$40 million for other *in situ* projects.

The SAGD *in situ* development uses horizontal drilling technology to inject steam into the deposit to heat the oil sands, lowering the viscosity of the bitumen.

Syncrude and MacKay River Operating and Overhead Costs



Syncrude reached record net production of 28,600 b/d in 2004.

Syncrude and MacKay River Production



When completed, the third well pad at MacKay River will increase production and maximize utilization of surface facilities.

OUTLOOK

2005 production expectations:

- Petro-Canada's share of Syncrude production to average 28,000 b/d;
- MacKay River bitumen production to average 24,000 b/d.

Growth plans:

- Syncrude Stage III expansion comes on-stream in 2006, adding 13,000 b/d over the ensuing two- to three-year ramp up period;
- application for next (second) SAGD project in 2005;
- increase production capacity at MacKay River by adding a third well pad;
- develop Fort Hills oil sands mining and upgrading project;
- advance SAGD technology through research and development.

2005 capital spending plans:

- \$35 million to enhance existing operations and comply with regulations at Syncrude;
- \$135 million to add a third well pad at MacKay River and replace the southwest quadrant mine at Syncrude;
- \$150 million to fund the Syncrude Stage III expansion;
- \$80 million to advance development of *in situ* oil sands leases.

Oil Sands production is expected to increase to about 52,000 b/d in 2005, compared to 45,200 b/d in 2004. The higher outlook reflects improved reliability and operating performance at MacKay River. The Syncrude Stage III expansion, scheduled for completion in mid-2006, will increase Petro-Canada's share of Syncrude's production capacity to approximately 42,000 b/d. Production will reach this level following a ramp up period of two to three years.

The Oil Sands 2005 capital expenditures of \$400 million are focused on providing additional production from existing projects. A third well pad will be added at MacKay River to increase reservoir production and maximize plant throughput. As a result, operating costs at MacKay River are expected to decline going forward as reliability improves and volumes grow. A further \$80 million will advance the future development of the Company's *in situ* oil sands leases at MacKay River and other leases. The Company's next *in situ* is expected to be developed on one of the existing leases with potential production of 30,000 to 40,000 b/d.

At the Edmonton refinery, Petro-Canada is investing to convert the facility to exclusively oil sands feedstocks and to produce low-sulphur products. By mid-2008, capital investment of \$1.2 billion will expand coker capacity and utilities, and add a new crude unit, a vacuum unit and new sulphur plants. This will enable the Company to directly upgrade 26,000 b/d of bitumen and process 48,000 b/d of sour synthetic crude oil, replacing the conventional light crude feedstock refined today. The refinery conversion program supports the long-term strategy and builds on the \$1.4 billion investment in gasoline and diesel desulphurization.

In early 2005, Petro-Canada became a 60% interest holder and operator of the Fort Hills oil sands mining project. The Company plans to develop this estimated 2.8 billion barrels of bitumen resource (1.7 billion barrels net to Petro-Canada) over a 30- to 40-year period.

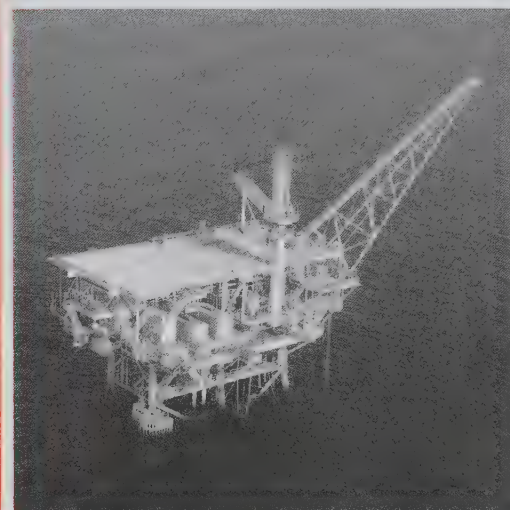
Q:

How does Petro-Canada see its International business adding value over the long term?

A:

Petro-Canada is well positioned to access reserves to supply growing market demand from three focused international areas.

The Hibiscus platform offshore Trinidad is the production facility for the NCMA-1 development.



Operations on the Hanze production platform offshore in The Netherlands.

International

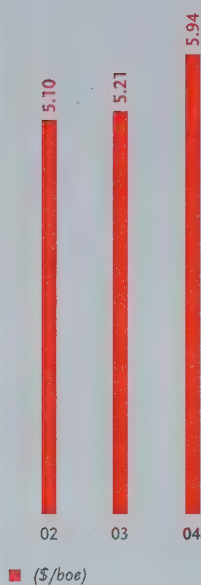
BUSINESS SUMMARY AND STRATEGY

International production and exploration interests are currently focused in three regions. In Northwest Europe, production comes from the U.K. and The Netherlands sectors of the North Sea. The North Africa/Near East region provides the major portion of International crude oil production from interests principally in Syria and Libya. In Northern Latin America, operations are focused in Trinidad and Venezuela.

The International business is the platform for Petro-Canada's global growth. The strategy is to access a sizeable international resource base using a three-fold approach to:

- expand and exploit the existing portfolio of assets;
- target new opportunities and acquisitions with a focus on long-life assets; and
- build a balanced exploration program to replace reserves over time.

International Operating and Overhead Costs



Acquisition of the Buzzard project has strengthened Petro-Canada's portfolio by adding higher netback barrels.

International Financial Results

(millions of dollars)

	2004	2003	2002
Net earnings	\$ 175	\$ 307	\$ 225
Unrealized loss on Buzzard derivative contracts	(205)	—	—
Gain on sale of assets	8	10	—
Earnings from operations	\$ 372	\$ 297	\$ 225
Kazakhstan impairment	—	(46)	—
International provisions	—	45	—
Earnings from operations excluding adjustments for one-time and unusual items	\$ 372	\$ 298	\$ 225
Cash flow from operating activities			
before changes in non-cash working capital	\$ 1,027	\$ 890	\$ 583
Expenditures on property, plant and equipment and exploration	\$ 1,824	\$ 525	\$ 221
Total assets	\$ 5,954	\$ 3,973	\$ 3,544

2004 COMPARED WITH 2003

International contributed earnings from operations adjusted for one-time and unusual items of \$372 million in 2004, up 25% from \$298 million in 2003. The earnings increase reflected higher realized commodity prices, partially offset by lower volumes and higher exploration and depreciation, depletion and amortization expenses.

Net earnings from International were \$175 million in 2004, down from \$307 million in 2003. Net earnings in 2004 included an after-tax unrealized loss on Buzzard derivative contracts of \$205 million and an \$8 million after-tax gain on the sale of non-core assets. Net earnings in 2003 included a \$10 million after-tax gain on the sale of non-core assets, a \$46 million provision related to the impairment of assets in Kazakhstan and a \$45 million positive adjustment related to the clarification of production rights and a tax provision of a former operation.

International oil and liquids realized prices averaged \$48.06/bbl in 2004, compared with \$39.10/bbl in 2003. International realized prices for natural gas averaged \$5.21/Mcf in 2004, compared with \$4.80/Mcf in 2003.

International production of crude oil and natural gas averaged 196,700 boe/d in 2004, compared with 210,000 boe/d in 2003. Higher production in Trinidad and Northwest Europe was offset by lower production in Syria due to natural declines in the existing mature fields.

International operating and overhead costs averaged \$5.94/boe in 2004, up from \$5.21/boe in 2003, reflecting lower production and rising industry costs.

2004 Operating Review and Strategic Initiatives

Northwest Europe

In 2004, Northwest Europe continued to provide high netback production. Although a maturing basin, small- to mid-size reserves can be produced economically, especially if tied back to the extensive existing infrastructure. Petro-Canada's production averaged 40,400 b/d of crude oil and natural gas liquids and 85 MMcf/d of natural gas in 2004, compared with 37,700 b/d and 80 MMcf/d, respectively, in 2003. The increase in production mainly reflected the new Clapham field, which came on-stream at the end of 2003.

The focus in Northwest Europe has been to expand and exploit the current portfolio. During 2004, Petro-Canada acquired a 29.9% interest in the Buzzard project in the U.K. sector of the North Sea. The Buzzard field has an estimated recovery of 550 MMbbls of oil, plus 18 MMboe of associated natural gas and natural gas liquids. Progress on the Buzzard field development was on schedule and on budget during 2004, with first oil expected by 2006. Other North Sea oil developments also progressed during the year. Both Pict and De Ruyter are expected to produce 10,000 b/d net to Petro-Canada, with on-stream dates in mid-2005 and late 2006, respectively.

North Africa/Near East

The North Africa/Near East region provides large resource potential with long-life, platform assets and is International's largest producing region. In 2004, Petro-Canada's production of crude oil and natural gas liquids averaged 126,600 b/d and 21 MMcf/d for natural gas, compared with averages of 143,100 b/d and 32 MMcf/d, respectively, in 2003. Lower volumes reflected declining production in the mature Syrian assets, partially offset by strong production in Libya.

In 2004, Petro-Canada continued to work on its expanded portfolio of operated exploration assets in Tunisia, Syria and Algeria. In Syria, the Company undertook extensive data gathering on Block II in preparation for shooting of both 2D and 3D seismic in 2005. In Tunisia, on the Melitta Block, Petro-Canada is currently preparing to drill the first of two exploration wells scheduled for 2005. The first well, which is onshore, should commence operations during the second quarter of 2005. The final timing of the second well, which is offshore, is dependent on securing a suitable drilling unit for the planned operations. In Algeria, the Company received final government approval for the Zotti Block. Preparations are ongoing for shooting of 2D seismic and drilling one well during 2005. These assets further business plans to build a balanced International exploration program for long-term growth.

Northern Latin America

Northern Latin America contains large potential in both offshore natural gas and conventional and heavy oil. Petro-Canada holds a 17% working interest in the North Coast Marine Area-1 gas development in Trinidad and a 50% interest in the La Ceiba block in Venezuela. In 2004, Petro-Canada's share of Trinidad production averaged 72 MMcf/d, up from 63 MMcf/d in 2003. The increase was a result of supplying full year production to Train 3 at the Atlantic LNG facility. Train 3 started operations in the second quarter of 2003.

Petro-Canada continued its negotiations with the Government of the Republic of Trinidad and Tobago for production-sharing contracts for Blocks 1a and 1b in the Gulf of Paria. Further discussions and clarification of the bid for Block 22 progressed. In Venezuela, the extended production test to evaluate commercial viability of the La Ceiba development began during 2004.

International capital expenditures in 2004 were \$606 million, with \$395 million directed to Northwest Europe primarily for North Sea developments, \$162 million invested in the North Africa/Near East region and \$49 million going toward the Northern Latin America region and other capital projects.

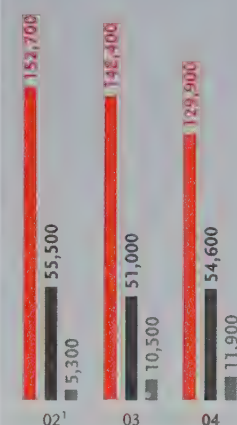
Business Development Opportunities

To deliver International's strategy of adding sizeable, long-life assets to the portfolio, the business has an experienced business development team. In 2004, this team pursued a number of significant opportunities such as participating in LNG projects, acquiring and developing established reserves in the Middle East and furthering exploration opportunities.

Complementing the proposed Gros-Cacouna LNG re-gasification terminal (page 20, North American Natural Gas, MD&A), Petro-Canada signed a Memorandum of Understanding (MOU) with OAO «Gazprom» (Gazprom) to investigate a joint project to ship Russian LNG to North American markets by 2009. The MOU covers options for Petro-Canada and Gazprom to jointly develop a liquefaction plant in the St. Petersburg region. Also included is the investigation of options for natural gas supplies to that LNG plant, and the re-gasification and marketing of natural gas in North America. With an international presence and extensive marketing experience, Petro-Canada is well positioned throughout the LNG value chain.

Negotiations to develop the Syria Middle Area Gas project ended early in 2005. The Government of the Syrian Arab Republic decided to develop the project rather than award it to a foreign consortium.

International Production



■ North Africa/Near East (boe/d)
■ Northwest Europe (boe/d)
■ Northern Latin America (boe/d)

¹ Production for North Africa/Near East and Northwest Europe in 2002 is based on the average daily rate, post acquisition. Northern Latin America production in 2002 is based on production from start-up in August 2002.

In 2004, Petro-Canada signed an MOU with Gazprom to investigate upstream LNG supply options and marketing in North America.

OUTLOOK

Production expectations in 2005:

- North Africa/Near East oil and gas production to average 114,000 boe/d;
- Northwest Europe oil and gas production to average 43,000 boe/d;
- Northern Latin America natural gas production to average 66 MMcf/d.

Growth plans:

- advance Pict and De Ruyter developments for 2005 and 2006 start-up, respectively;
- progress Buzzard project in 2005, for first oil in 2006;
- expand exploration program to include activity in Northwest Europe and North Africa/Near East;
- continue to pursue new business opportunities in LNG and established reserves in the Middle East.

Capital spending plans in 2005:

- \$195 million for reserves replacement spending in core areas;
- \$470 million for new North Sea growth projects;
- \$120 million for exploration and new ventures;
- \$40 million for other expenditures, including a provision for the potential development of La Ceiba.

International production is expected to be 168,000 boe/d in 2005, compared with production of 196,700 boe/d in 2004. Lower production reflects declines in Syria and Northwest Europe.

International 2005 capital expenditures of approximately \$825 million are primarily focused on significant near-term production growth, such as Buzzard, Pict and De Ruyter. These projects are well under way with an allocation of approximately \$470 million of capital in 2005. Production from these projects is on track to come on-stream in 2005 and 2006.

Reserves replacement spending in core areas is expected to be about \$195 million in 2005. The \$120 million allocated to exploration and new ventures will initiate programs on new acreage in the North Sea, Tunisia, Syria and Algeria. This capital will also develop prospects around existing operations in North Africa and the North Sea.

Other expenditures, including a provision for the potential development of La Ceiba, will total \$40 million. Should Petro-Canada receive a positive evaluation of the production test at La Ceiba, development of the project could proceed and come on-stream as early as 2008, building to peak production of 13,000 b/d (net).

In 2005, Petro-Canada expects to receive a decision from the Government of the Republic of Trinidad and Tobago for production-sharing contracts for Blocks 1a and 1b in the Gulf of Paria. A successful bid on Block 22 would also provide Petro-Canada with another quality exploration opportunity.

During 2005, International will also continue its investigation of potential LNG supply and marketing options with Gazprom.

Q:

What volume of production does Petro-Canada expect from the upstream businesses in 2005?

A:

Our 2005 upstream production outlook is expected to fall in the range of 415,000 to 440,000 boe/d, with significant production growth over the next three years as new projects come on-stream.

Upstream Production

2004 COMPARED WITH 2003

In 2004, production of crude oil, natural gas liquids and natural gas averaged 451,100 boe/d, compared with 464,500 boe/d in 2003. Production gains from the Oil Sands, the U.K. and the addition of the U.S. Rockies were more than offset by declines in Syria and Western Canada, and production outages at Terra Nova.

2004 Average Daily Production Volumes	North American Natural Gas	East Coast Oil	Oil Sands	International	Total
Crude oil, natural gas liquids and bitumen (b/d)					
net before royalties	15,300	78,200	16,600	167,000	277,100
net after royalties	11,400	75,100	16,500	107,800	210,800
Synthetic crude oil (b/d)					
net before royalties	—	—	28,600	—	28,600
net after royalties	—	—	28,300	—	28,300
Natural gas (MMcf/d)					
net before royalties	695	—	—	178	873
net after royalties	530	—	—	139	669
Total volumes (boe/d)					
net before royalties	131,100	78,200	45,200	196,600	451,100
net after royalties	99,700	75,100	44,800	131,000	350,600

2003 Average Daily Production Volumes	North American Natural Gas	East Coast Oil	Oil Sands	International	Total
Crude oil, natural gas liquids and bitumen (b/d)					
net before royalties	16,900	86,100	10,700	180,800	294,500
net after royalties	12,600	84,000	10,600	115,600	222,800
Synthetic crude oil (b/d)					
net before royalties	—	—	25,400	—	25,400
net after royalties	—	—	25,100	—	25,100
Natural gas (MMcf/d)					
net before royalties	693	—	—	175	868
net after royalties	521	—	—	149	670
Total volumes (boe/d)					
net before royalties	132,300	86,100	36,100	210,000	464,500
net after royalties	99,500	84,000	35,700	140,400	359,600

2005 Production Outlook

In 2005, production from Petro-Canada's upstream businesses is expected to decrease slightly compared to 2004 levels. This is mainly due to declines in Syria and Northwest Europe. Factors that may impact production during 2005 include reservoir performance, drilling results, facility reliability and the execution of planned turnarounds at certain gas plants, Terra Nova, Hibernia, and Syncrude, and other factors. Investments in existing growth projects will provide additional production in 2006 and 2007. Exploration and new venture investments will also add longer-term production to the Company's portfolio of assets.

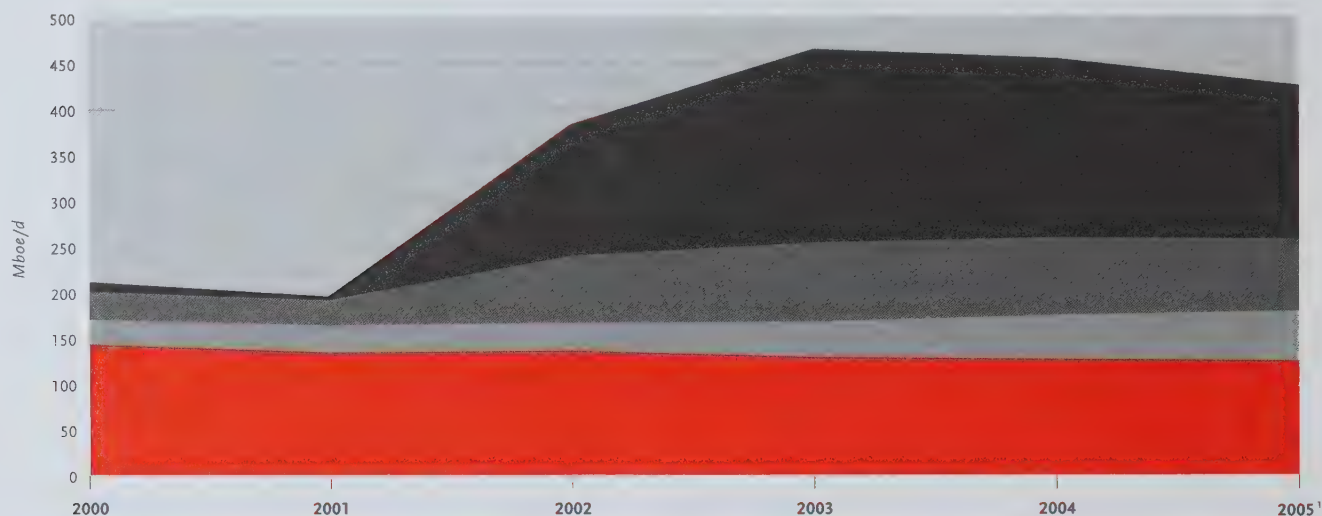
Consolidated Production (boe/d)

2005 Outlook (+/-)

North American Natural Gas	
Natural gas	113,000
Liquids	14,000
East Coast Oil	77,000
Oil Sands	
Syncrude	28,000
MacKay River	24,000
International	
North Africa/Near East	114,000
Northwest Europe	43,000
Northern Latin America	11,000
Total	415,000 – 440,000

PRODUCTION OVERVIEW

- International
- East Coast Oil
- Oil Sands
- North American Natural Gas



¹ As per the Company's forecast.

Reserves

At year-end 2004, proved reserves before royalties totaled 1,214 million barrels of oil equivalent (MMboe), including 331 MMbbls of synthetic crude oil from oil sands mining.

This amount was down slightly from 1,220 MMboe at year-end 2003. Exploration, development and acquisition activities all contributed to the Company's overall replacement of its reserves. As a result of better than forecast reservoir performance at Hibernia, Petro-Canada revised its life of field reserves estimate upward from 835 MMbbls to 940 MMbbls (from 167 MMbbls to 188 MMbbls, net Petro-Canada). This revision added more than 15 MMbbls to year-end 2004 proved reserves at Hibernia. However, in complying with U.S. Securities Exchange Commission (SEC) requirements to use prices and costs as of the date of the reserves estimate, the Company reclassified 22 MMbbls of proved bitumen reserves at its MacKay River development as probable reserves. This reflects abnormally high light/heavy crude oil differentials and high costs for synthetic crude oil (used as a blending material for transporting the bitumen to market) at year-end 2004. This reclassification did not have any financial impact on the Company and Petro-Canada continues to view its bitumen reserves and resources as an integral part of its overall growth portfolio. Absent this reclassification, the Company would have replaced 110% of its 2004 production.

As part of Petro-Canada's long-term reserves replacement strategy, the Company added exploration capability and funding – especially internationally – to develop a balanced exploration program aimed at increasing the reserves base over time. In particular, Petro-Canada will target long-life reserves and aim for greater operatorship. The Company's goal is a growth portfolio that provides a balanced range of risk/reward opportunities. The new exploration lands recently acquired in Syria, Tunisia and Algeria are early examples of initiatives in the International business. In Canada, Petro-Canada continues to pursue opportunities off the East Coast and North of 60. In Western Canada, the Company plans to gradually increase the exploration program to improve reserves replacement.

In order to harmonize its oil and gas disclosure in both Canada and the U.S., Petro-Canada applied for, and received, certain exemptions to reserves disclosure requirements as set out in National Instrument 51-101; Standards of Disclosure for Oil and Gas Activities (NI 51-101), which was adopted in 2003 by the securities regulatory authorities in Canada. These exemptions permit Petro-Canada to use its own staff of qualified reserves evaluators to prepare the Company's reserves estimates and to use SEC and Financial Accounting Standards Board (FASB) standards when reporting reserves.

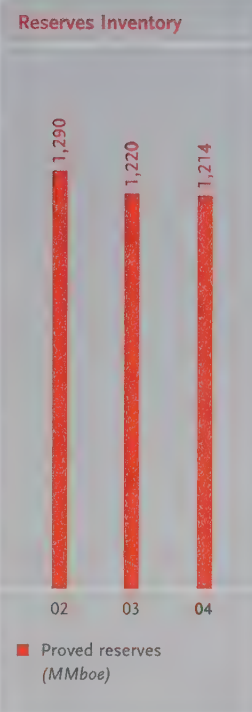
Petro-Canada strongly believes that the use of its own staff of qualified reserves evaluators, who are familiar with the Company's oil and gas assets as a result of working with them on a day-to-day basis, combined with independent third-party assessment of both its reserves processes and its reserves estimates, provides a level of confidence in its reserves data that is at least as good as that which would be provided if the work was done solely by a third party.

Petro-Canada's staff of qualified reserves evaluators determines the Company's reserves data and quantities based on corporate-wide policies, procedures and practices. These reserves policies, procedures and practices conform to the requirements of Canadian, as well as the SEC, regulations and the Association of Professional Engineers, Geologists and Geophysicists of Alberta Standard of Practice for the Evaluation of Oil and Gas Reserves for Public Disclosure.

To confirm the quality of the reserves policies, procedures and practices and the internally generated reserves estimates, Petro-Canada employs the services of independent qualified engineering evaluators/auditors. For 2004, independent petroleum reservoir engineering consultants Sproule Associates Limited (Sproule) and Gaffney, Cline & Associates Ltd. (GCA) conducted assessments of Petro-Canada's hydrocarbon reserves. GCA completed an independent audit of 78% of the Company's proved crude oil, natural gas and natural gas liquids reserves outside of North America. Similarly, Sproule audited 77% of Petro-Canada's Canadian proved conventional reserves and reviewed Syncrude. Sproule also conducted an evaluation of Petro-Canada's proved, probable and possible reserves in the U. S. Rockies. The independent auditors'/evaluators' reports concluded that the Company's year-end 2004 proved reserves are reasonable.

Sproule and GCA also audited Petro-Canada's reserves policies, procedures and practices. They concluded that Petro-Canada's reserves booking standards meet applicable disclosure regulations, that management is complying with those standards, and that the reserves process is carried out in a manner and standard consistent with the auditors' practices. In addition, PricewaterhouseCoopers LLP, as contract internal auditor, tested the non-engineering management control processes used in establishing reserves.

Detailed information about Petro-Canada's proved reserves of crude oil, natural gas liquids, natural gas, bitumen and synthetic crude oil before and after royalties is available on pages 70 to 73 of this Annual Report.



Petro-Canada reserves processes and estimates are assessed by independent consultants.

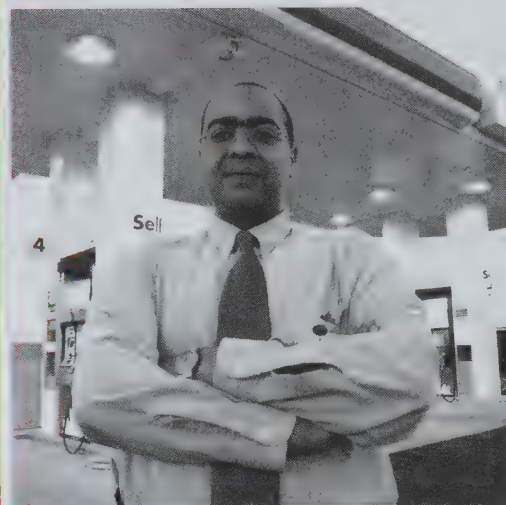
Q:

What progress has Petro-Canada made to improve the Downstream base business profitability?

A:

Progress during 2004 included successfully progressing consolidation of Eastern Canada refining operations, the sale of high-margin lubricants rising to 67% and convenience store sales increasing 11% year-over-year.

Yasir Suliman operates one of Petro-Canada's award-winning retail stores.



At Petro-Canada's Mississauga lubricants plant, employees, like Tony Pollock, produce the purest lubricating oil base stocks in Canada.

Downstream

BUSINESS SUMMARY AND STRATEGY

The Downstream operations include three refineries with a total rated capacity of 49,000 cubic metres (308,000 barrels) per day.¹ The stand alone lubricants plant is the largest producer of lubricant base stocks in Canada. In 2004, Petro-Canada accounted for about 15% of the Canadian industry's total refining capacity. Product sales represented about 17% of total petroleum products sold in Canada.

Downstream strategies are focused on strengthening the foundations for improved profitability through effective capital investment and discipline over controllable factors. The goal is superior returns and growth, including a 12% return on capital employed, based on a mid-cycle business environment. Key features of the strategy include:

- achieving and maintaining first quartile operating performance;
- advancing Petro-Canada as the "brand of choice" for Canadian gasoline consumers; and
- building on market strengths and increasing sales of high-margin specialty lubricants.

¹ Capacity revised, on a pro rata basis, from 49,800 cubic metres (313,000 barrels) per day in 2003 to reflect partial closure of Oakville refinery operations, effective November 12, 2004.

Downstream Financial Results

(millions of dollars)

	2004	2003	2002
Net earnings	\$ 314	\$ 248	\$ 252
Gain (loss) on sale of assets	4	(15)	3
Earnings from operations	\$ 310	\$ 263	\$ 249
Income tax adjustment	2	34	—
Oakville closure costs	(46)	(151)	—
Earnings from operations excluding adjustments for one-time and unusual items	\$ 354	\$ 380	\$ 249
Cash flow from operating activities before changes in non-cash working capital	\$ 556	\$ 601	\$ 380
Expenditures on property, plant and equipment	\$ 839	\$ 424	\$ 344
Total assets	\$ 4,462	\$ 3,827	\$ 3,836

2004 COMPARED WITH 2003

Downstream contributed earnings from operations, adjusted for one-time and unusual items of \$354 million in 2004, down 7% from \$380 million in 2003. The impact of rising crude prices on margins for retail and heavy products and a stronger Canadian dollar more than offset the benefits of favourable U.S. refining margins and a wider light/heavy crude price differential in 2004.

Net earnings from Downstream were \$314 million in 2004, up from \$248 million in 2003. Net earnings in 2004 included a \$4 million after-tax gain on the sale of assets, a \$2 million positive adjustment to reflect a reduction in provincial income tax rates and a \$46 million after-tax charge for additional depreciation and other charges related to the previously announced consolidation of the Eastern Canada refinery operations. Net earnings in 2003 included a \$15 million after-tax loss on asset sales related to the selective rationalization of marketing networks in Eastern Canada, a \$34 million positive adjustment to reflect the changes in federal and provincial tax rates and a \$151 million charge related to the closure of the Oakville refinery.

Excluding the impacts of one-time and unusual items, Refining and Supply contributed 2004 operating earnings of \$288 million, which was unchanged from 2003. Earnings in 2004 were increased by favourable U.S. refining margins, wider light/heavy crude price differentials and a positive “last-in, first-out” (LIFO) inventory valuation adjustment associated with the Oakville closure. This was offset by the effects of a 2% decline in overall crude capacity utilization at Downstream’s three refineries and lower asphalt and heavy fuel oil margins, as prices failed to keep pace with rising crude oil costs in the second half of 2004. Petro-Canada, as the leading player in asphalt and heavy fuel oil in Eastern Canada, was particularly impacted by the low-margin environment.

Marketing contributed earnings from operations excluding one-time and unusual items of \$66 million, down from \$92 million in 2003. The decrease in earnings was primarily attributable to increased retail price competition in 2004.

2004 Operating Review and Strategic Initiatives

Total crude oil processed in 2004 averaged 48,200 cubic metres per day (m³/d), down from 49,900 m³/d in 2003. The overall utilization rate at the three refineries, adjusted for the partial closure of the Oakville refinery on November 12, 2004, averaged 98% in 2004, down slightly from 100% in 2003. The decline reflected a 35-day turnaround related to the Eastern Canada consolidation and a major turnaround at the Edmonton refinery for maintenance and to facilitate tying in low-sulphur gasoline equipment.

Total Downstream sales decreased slightly, to an average 56,600 m³/d from 56,800 m³/d in 2003. Lower gasoline and distillate sales were mostly offset by stronger sales of lubricants and unfinished refinery stock. Non-petroleum product sales continued to demonstrate strong growth with convenience store sales rising 11% from the previous year.

Total Downstream operating, marketing and general and administration unit costs of 6.4 cents/litre were up slightly from 6.2 cents/litre in 2003. The increase mainly reflected higher maintenance and shutdown costs.

Downstream Operating, Marketing and General Costs

Per litre costs reflected higher maintenance and shutdown costs.



Petro-Canada is successfully consolidating Eastern Canada refineries.

Refinery Utilization

Lower refinery utilization was due to the Eastern Canada consolidation and a major turnaround at the Edmonton refinery allowing tie-in of low-sulphur gasoline equipment.



New image sites combine highly visible and attractive design elements with improved traffic flow and convenience for customers.

Gasoline Throughput per Retail Site

Total Downstream sales per retail site continued to grow in 2004.



In 2004, Downstream completed its most aggressive capital plan ever. The Downstream business continued to focus on improving refining assets and operations, becoming the “brand of choice” in sales and marketing, and realizing the full potential of the lubricants business.

In Refining and Supply, key initiatives were the consolidation of Eastern Canada refining and supply operations to Montreal and the ongoing work to convert the Edmonton refinery to process oil sands feedstock. The Eastern Canada consolidation is on schedule, including the successful reversal and expansion of the Trans-Northern Pipelines Inc. pipeline and completion of logistics tie-ins at the Montreal refinery to supply the Ontario market. The consolidation work also included a successful 35-day crude unit turnaround at the Montreal refinery to expand the plant’s crude capacity. Excellent safety and reliability were maintained at the Oakville refinery during the transition. The refinery will operate at a reduced level into early 2005 to increase short-term supply flexibility through the transition period.

The largest maintenance shutdown ever at the Edmonton refinery was completed on time and on budget in 2004, with an outstanding safety record. The turnaround also included work to successfully tie-in low-sulphur gasoline equipment. Both the Edmonton and Montreal refineries were producing gasoline in compliance with new federal ultra-low sulphur gasoline regulations well in advance of the January 1, 2005 deadline.

Overall plant reliability, a critical component of success in the refining business, improved in 2004. However, outstanding performance at Edmonton, Oakville and the lubricants plant was offset by lower reliability at the Montreal refinery. Work undertaken to address this issue through an increased focus on operations and maintenance procedures, as well as selective equipment upgrades, should improve reliability in 2005.

Downstream capital expenditures for plant, property and equipment were \$839 million for 2004. A substantial portion of the 2004 spending was directed to produce cleaner-burning diesel fuels. The Downstream business remained focused on positioning Petro-Canada for improved profitability, accelerating growth oriented projects primarily in the retail and wholesale networks.

The focus in Marketing was on profitable growth through initiatives directed at the retail and PETRO-PASS truck stop networks. Petro-Canada led the industry in key urban market metrics and continued to improve the fundamentals of the retail business with more than 85% of the re-imaging program complete. Fast-tracking this re-imaging program allowed realization of industry-leading throughputs, with annual gasoline sales from re-imaged sites within the Company’s network now averaging in excess of 6.8 million litres per site. Based on this success, the Company extended this new image program to independent retailers. More than 35% of these retailers elected to invest their capital in the new image standard.

Petro-Canada continued to leverage its position as “Canada’s Gas Station,” with innovative product developments and a continuing track record of “new product firsts” in the industry. In September 2004, the Downstream business introduced the Citi Petro-Points MasterCard, the first general-purpose credit card in North America to offer cardholders an instant discount on gasoline. The Company also accelerated the roll out of the Cash Point program, the industry’s first privately owned automated bank machine network. Petro-Canada also continued to focus on expanding non-petroleum revenue base, as evidenced by the 11% year-over-year sales growth of the convenience store business, and the 7% increase in same-store sales in 2004 compared to 2003.

In the Wholesale business, the focus was on improving the sales mix and leveraging the best-in-class position in the commercial road transport and bulk fuels channels. The PETRO-PASS network of 213 truck stop facilities is the leading national marketer of fuel in the commercial road transport segment in Canada. In 2004, the network was further expanded and upgraded, increasing sales volume in this high-value channel. In bulk fuels, Petro-Canada concentrated on the successful integration of acquisitions in the home heat business.

In 2004, the Lubricants business focused on growing volume in high-margin sales and improving plant reliability. Petro-Canada made great strides in improving reliability by intensifying efforts to optimize operations and maintenance procedures based on industry best practices. Despite continued soft demand in the key U.S. export market, Lubricants sales totaled 833 million litres in 2004, an increase of 8% compared to sales volume of 768 million litres in 2003. Over the last five years, growth in high-margin sales has averaged more than 11% per year. In 2004, high-margin sales rose 11%, resulting in 67% of production going into high-margin markets. Lubricants continues to be well positioned for profitable future growth as tougher performance and environmental standards increase global demand for higher quality base oils and finished products.

OUTLOOK

Growth plans:

- complete the closure of the Oakville refinery;
- drive for first quartile refinery reliability;
- increase service station network effectiveness with a focus on increasing non-petroleum revenue;
- increase sales of high-margin, value-added lubricants;
- invest in Montreal and Edmonton refineries to produce low-sulphur diesel;
- advance Edmonton refinery conversion program to process oil sands based feedstocks by 2008.

2005 capital spending plans:

- \$625 million primarily focused on diesel desulphurization at Montreal and Edmonton refineries;
- \$90 million for Edmonton refinery conversion program;
- \$205 million for sustaining investments and new growth opportunities.

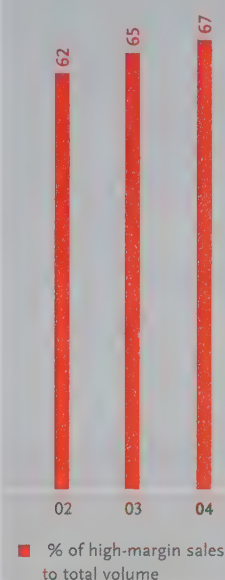
While the largest component of the Downstream's approximate \$920 million capital investment will be for regulatory compliance, business spending for 2005 also supports the strategy to improve base business profitability and pursue profitable growth.

Approximately \$625 million will go to modify the Montreal and Edmonton refineries to produce low-sulphur distillates in line with regulations, which come into effect June 1, 2006. This includes the pre-investment for the Edmonton refinery to process oil sands feedstocks in the future. An additional \$85 million will be invested to sustain existing operations with the main focus on improving plant reliability at the Montreal refinery and the Mississauga lubricants plant.

The Downstream business also plans to spend about \$120 million to improve the profitability of the base business. This will include investments to advance the development of the retail network and to increase non-petroleum revenue. In keeping with the strategy to pursue profitable growth, Downstream will invest approximately \$90 million to begin the detailed engineering work to convert the Edmonton refinery to run 100% oil sands crude feedstock. Petro-Canada will also begin work to debottleneck the Mississauga plant as the high-margin, specialty lubricants business grows.

Lubricants High-Margin Sales

High-margin lubricants sales increased 2% compared to 2003.



The Lubricants strategy remained focused on growing volume in high-margin sales and improving plant reliability.

Shared Services

Shared Services includes investment income, interest expense, foreign currency translation and general corporate revenue and expenses.

Shared Services Financial Results

(millions of dollars)

	2004	2003	2002
Net earnings (loss)	\$ (63)	\$ 58	\$ (196)
Gain (loss) on sale of assets	(1)	1	—
Foreign currency translation	63	239	(52)
Net loss from operations	\$ (125)	\$ (182)	\$ (144)
Income tax adjustment	(1)	(11)	—
Net loss from operations excluding adjustments for one-time and unusual items	\$ (124)	\$ (171)	\$ (144)
Cash flow from operating activities before changes in non-cash working capital	\$ (106)	\$ (100)	\$ (104)

2004 COMPARED WITH 2003

Shared Services net loss from operations adjusted for one-time and unusual items was \$124 million in 2004, compared to \$171 million in 2003. This decrease primarily reflected lower interest expense and general expenses.

Shared Services net loss was \$63 million in 2004, compared to net earnings of \$58 million in 2003. Net expenses in 2004 included a \$1 million after-tax loss on the sale of assets, a \$63 million foreign currency translation gain on U.S. dollar-denominated long-term debt and a \$1 million charge to reflect a change in the provincial income tax rate. Net earnings in 2003 included a \$1 million after-tax gain on the sale of assets, a \$239 million foreign currency translation gain on U.S. dollar-denominated long-term debt and an \$11 million charge to reflect changes in federal and provincial income tax rates. The 2004 and 2003 foreign currency translation gain on U.S. dollar-denominated long-term debt reflected the strengthening of the Canadian dollar versus the U.S. dollar.

Q:

What is Petro-Canada's approach to disclosure?

A:

Petro-Canada is committed to open and fair disclosure in compliance with securities regulations and generally accepted accounting standards.

Financial Reporting

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. The Audit, Finance and Risk Committee of the Board of Directors regularly reviews the Company's critical accounting policies and any significant changes thereto. A summary of the significant accounting policies used by Petro-Canada can be found in Note 1 to the 2004 Consolidated Financial Statements. The following discussion outlines what management believes to be the most critical accounting policies involving the use of significant estimates or assumptions.

Property, Plant and Equipment/Depreciation, Depletion and Amortization

Investments in exploration and development activities are accounted for under the successful efforts method. Under this method, the acquisition costs of unproved acreage, the costs of exploratory wells pending determination of proved reserves, the costs of wells which are assigned proved reserves and development costs, including costs of all wells, are capitalized. The cost of unsuccessful wells and all other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Capitalized costs of oil and gas producing properties are depreciated and depleted using the unit of

production method based upon estimated reserves (see Estimated Oil and Gas Reserves discussion on page 40). Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depreciation and depletion related to the capitalized costs of property, plant and equipment. A revision in reserves estimates could result in either a higher or lower depreciation and depletion charge to net earnings. A downward revision in reserves could result in a write-down of oil and gas producing properties as part of the impairment assessment (see Asset Impairment discussion below).

Asset Retirement Obligations

The Company currently records the obligation for estimated asset retirement costs at fair value when incurred. Factors that can affect the fair values of the obligations include the expected costs and the useful lives of the assets. Cost estimates are influenced by factors such as the number and type of assets subject to asset retirement obligations, the extent of work required and changes in environmental legislation. A revision to the estimated costs or useful lives of the assets could result in an increase or decrease in the total obligation which would change the amount of amortization and accretion expense recognized in net earnings over time.

Asset Impairment

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated undiscounted future cash flows to the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves (see Estimated Oil and Gas Reserves discussion on page 40), future commodity prices and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices or an increase in operating costs could result in an impairment of an asset's carrying value.

Purchase Price Allocation

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair value at the time of the acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of property, plant and equipment acquired generally require the most judgment, and include estimates of reserves acquired (see Estimated Oil and Gas Reserves discussion on page 40), future commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities, and goodwill in the purchase price allocation. Future net earnings can be affected as a result of changes in future depreciation and depletion, asset impairment or goodwill impairment.

Goodwill Impairment

Goodwill is subject to impairment tests annually, or as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill. The determination of fair value requires management to make assumptions and estimates about recoverable reserves (see Estimated Oil and Gas Reserves discussion on page 40), future commodity prices, operating costs, production profiles and discount rates. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in future commodity prices, an increase in operating costs or an increase in discount rates could result in an impairment of all or a portion of the goodwill carrying value in future periods.

Estimated Oil and Gas Reserves

Reserves estimates, although not reported as part of the Company's Consolidated Financial Statements, can have a significant effect on net earnings as a result of their impact on depreciation and depletion rates, asset impairments and goodwill impairment (see discussion of these items on pages 38 and 39). The Company's staff of qualified reserves evaluators performs internal evaluations on all of its oil and gas reserves on an annual basis using corporate-wide policies, procedures and practices. Independent qualified petroleum reservoir engineering consultants also conduct annual evaluations, technical audits and/or reviews of a significant portion of the Company's reserves and audit the Company's reserves policies, procedures and practices. In addition, the Company's contract internal auditors test the non-engineering management control processes used in establishing reserves. However, the estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as geoscientific interpretation, commodity prices, operating and capital costs, and production forecasts, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

Employee Future Benefits

The Company maintains defined benefit pension plans and provides certain post-retirement benefits to qualifying retirees. Obligations under employee future benefits plans are recorded net of plan assets where applicable. The cost of pension and other post-retirement benefits are actuarially determined by an independent actuary using the projected benefit method pro rated based on service. The determination of these costs requires management to estimate or make assumptions regarding the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover, discount rates and return on plan assets. Changes in these estimates or assumptions could result in an increase or decrease to the accrued benefit obligation and the related costs for both pensions and other post-retirement benefits.

Income Taxes

The Company follows the liability method of accounting for income taxes whereby future income taxes are recognized based on the differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The determination of the income tax provision is an inherently complex process requiring management to interpret continually changing regulations and to make certain judgments. While income tax filings are subject to audits and reassessments, management believes adequate provision has been made for all income tax obligations. However, changes in the interpretations or judgments may result in an increase or decrease in the Company's income tax provision in the future.

Contingencies

The Company is involved in litigation and claims in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company as at December 31, 2004. However, the determination of contingent liabilities relating to the litigation and claims is a complex process that involves judgments as to the outcomes and interpretation of laws and regulations. Changes in the judgments or interpretations may result in an increase or decrease in the Company's contingent liabilities in the future.

ACCOUNTING CHANGES

Asset Retirement Obligations

Effective January 1, 2004, the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants (CICA) on accounting for asset retirement obligations. The new standard requires the fair values of asset retirement obligations to be recorded as liabilities when incurred and the related assets be increased by the amount of these liabilities. Over time, the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets. Asset retirement obligations are not recorded for those assets which have an indeterminate useful life. The impact of this change has been disclosed in Note 2 of the Consolidated Financial Statements.

Reclassification of Costs

Pursuant to the new CICA section 1100 “Generally Accepted Accounting Principles,” which provides guidance on the sources to consult when selecting accounting policies, the Company began accounting, effective January 1, 2004, for certain transportation costs, third-party gas purchases and diluent purchases as expenses in the Consolidated Statement of Earnings. Previously, these costs were netted against revenue. Prior years’ comparatives have been restated.

Hedging Relationships

Effective January 1, 2004, the Company adopted Accounting Guideline 13 (AcG 13), “Hedging Relationships,” which resulted in changes to the conditions as to when hedge accounting may be obtained. As a result, certain of the Company’s risk management derivative instruments no longer qualify as accounting hedges and are accounted for as required under Emerging Issues Committee (EIC) 128, “Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments.” EIC 128 requires that all derivative instruments that do not qualify, or are not designated as a hedge under AcG 13, be recorded on the Consolidated Balance Sheet at fair value as either an asset or liability with changes in fair value recognized in earnings.

RECENT PRONOUNCEMENTS

Pursuant to recent guidance on the classification of cash flows relating to asset securitization transactions, the Company has included the proceeds from its 2004 sale of accounts receivable as part of cash flows from operating activities. The Company had previously reported these proceeds as part of investing activities when reporting its quarterly results in 2004 and will reclassify the comparative amounts when quarterly results are reported in 2005.

RELATED-PARTY TRANSACTIONS

On September 29, 2004, the Government of Canada completed its offering to the public of its entire remaining interest in Petro-Canada. Transactions with the Government of Canada and its agencies prior to the sale were in the normal course of business and on the same terms as those accorded to non-related parties.

SHARE DATA

The authorized share capital of Petro-Canada consists of an unlimited number of common shares and an unlimited number of preferred shares issuable in series designated as either senior preferred shares or junior preferred shares. As at March 3, 2005, there were 260,358,471 common shares outstanding and no preferred shares outstanding. For details of the Company’s share capital and stock options outstanding, refer to Notes 20 and 21 to the 2004 Consolidated Financial Statements.

ADDITIONAL INFORMATION

Copies of this MD&A and the following Consolidated Financial Statements, as well as the Company’s latest Annual Information Form and Management Proxy Circular may be obtained from the Company’s Web site at www.petro-canada.ca or by mail upon request from the corporate secretary, 150 – 6th Avenue S.W., Calgary, Alberta, T2P 3E3. Other disclosure documents, and any reports, statements or other information filed by Petro-Canada with the Canadian provincial securities commissions or other similar regulatory authorities is accessible through the internet on the Canadian System for Electronic Document Analysis and Retrieval, which is commonly known by the acronym SEDAR and is located at www.sedar.com. SEDAR is the Canadian equivalent of the U.S. SEC’s Electronic and Document Gathering and Retrieval System, which is commonly known by the acronym EDGAR and is located at www.sec.gov.

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

The preparation and presentation of the Company's Consolidated Financial Statements and the overall quality of the Company's financial reporting are the responsibility of management. The financial statements have been prepared in accordance with generally accepted accounting principles and necessarily include estimates which are based on management's best judgments. Information contained elsewhere in the Annual Report is consistent, where applicable, with that contained in the financial statements.

Management is also responsible for installing and maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of financial statements, and believes that the system of internal controls they have installed has operated effectively in 2004.

Deloitte & Touche LLP, a firm of chartered accountants, were appointed by the shareholders as external auditors of the Company to conduct an independent examination and express their opinion on the Consolidated Financial Statements. The Auditors' Report outlines the auditors' opinion and the scope of their examination. The services provided to the Company by the external auditors are now restricted to the audit of the Consolidated Financial Statements and audit-related services. The only non-audit service provided was the licensing of access to industry databases and the Company cancelled those licences in 2004. The Company engaged PricewaterhouseCoopers LLP as contract auditor to provide internal audit services.

The Board of Directors is responsible for overseeing management's performance of its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility with the assistance of the Audit, Finance and Risk Committee of the Board of Directors.



Ron A. Brenneman
President and Chief Executive Officer



E.F.H. Roberts
Executive Vice-President and Chief Financial Officer

February 16, 2005

AUDIT, FINANCE AND RISK COMMITTEE OF THE BOARD OF DIRECTORS

The Audit, Finance and Risk Committee, which is composed of not fewer than three (currently six) directors who are not employees of the Company, assists the Board of Directors in the discharge of its responsibility for overseeing management's performance of the financial reporting and internal control responsibilities. The Committee reviews the annual and quarterly Consolidated Financial Statements, accounting policies and the overall quality of the Company's financial reporting, and the financial information contained in prospectuses and in reports filed with regulatory authorities, as required. The Committee also reviews and makes recommendations to the Board of Directors regarding financial matters and oversees the process that management has in place to identify business risks.

With respect to the external auditors, the Committee reviews and approves the terms of engagement, the scope and plan for the external audit and reviews the results of the audit and the Auditors' Report. The external auditors report to the Committee and to the Board of Directors. The Committee discusses the external auditors' independence from management and the Company with the auditors and receives written confirmation of their independence. The Committee also recommends to the Board of Directors the external auditors to be appointed by the shareholders and approves in advance fees for the external auditors' services.

With respect to the contract auditor's engagement to provide internal audit services, the Committee reviews the engagement contract, reviews and approves the scope and plan for the internal audit, receives periodic reports and reviews significant findings and recommendations. The contract auditor reports to the Committee and to the Board of Directors.

Senior management, the external auditors and the contract auditor attend all Audit, Finance and Risk Committee meetings and each is provided with the opportunity to meet privately with the Committee.



Paul D. Melnuk
Chairman of the Audit, Finance and Risk Committee

February 16, 2005

AUDITORS' REPORTS

To the Shareholders of Petro-Canada:

We have audited the Consolidated Balance Sheet of Petro-Canada as at December 31, 2004 and 2003 and the Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the years in the three-year period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Deloitte & Touche LLP

Deloitte & Touche LLP
Chartered Accountants
Calgary, Alberta, Canada

February 16, 2005

COMMENTS BY AUDITORS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

In the United States of America, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have been implemented in the financial statements, such as the changes described in Note 2 to the Consolidated Financial Statements of Petro-Canada. Our report to the shareholders dated February 16, 2005 is expressed in accordance with Canadian reporting standards, which do not require a reference to such changes in accounting principles in the Auditors' Report when the changes are properly accounted for and adequately disclosed in the financial statements.

Deloitte & Touche LLP

Deloitte & Touche LLP
Chartered Accountants
Calgary, Alberta, Canada

February 16, 2005

Consolidated Statement of Earnings

(stated in millions of Canadian dollars, except per share amounts)

For the years ended December 31,	2004	2003 (Note 2)	2002 (Note 2)
REVENUE			
Operating	\$ 14,687	\$ 12,887	\$ 10,374
Investment and other income (Note 4)	(310)	12	—
	14,377	12,899	10,374
EXPENSES			
Crude oil and product purchases	6,740	5,620	4,837
Operating, marketing and general (Note 5)	2,690	2,557	2,222
Exploration (Note 15)	235	271	301
Depreciation, depletion and amortization (Notes 5 and 15)	1,402	1,560	977
Foreign currency translation (Note 6)	(77)	(251)	52
Interest	142	182	187
	11,132	9,939	8,576
EARNINGS BEFORE INCOME TAXES	3,245	2,960	1,798
PROVISION FOR INCOME TAXES (Note 7)			
Current	1,461	1,247	959
Future	27	63	(116)
	1,488	1,310	843
NET EARNINGS	\$ 1,757	\$ 1,650	\$ 955
EARNINGS PER SHARE (Note 8)			
Basic	\$ 6.64	\$ 6.23	\$ 3.63
Diluted	\$ 6.55	\$ 6.16	\$ 3.59

Consolidated Statement of Retained Earnings

(stated in millions of Canadian dollars)

For the years ended December 31,	2004	2003 (Note 2)	2002 (Note 2)
RETAINED EARNINGS AT BEGINNING OF YEAR, as previously reported	\$ 3,943	\$ 2,380	\$ 1,511
Retroactive application of change in accounting for asset retirement obligations (Note 2)	(133)	(114)	(95)
RETAINED EARNINGS AT BEGINNING OF YEAR, as restated	\$ 3,810	\$ 2,266	\$ 1,416
Net earnings	1,757	1,650	955
Dividends on common shares	(159)	(106)	(105)
RETAINED EARNINGS AT END OF YEAR	\$ 5,408	\$ 3,810	\$ 2,266

Consolidated Statement of Cash Flows

(stated in millions of Canadian dollars)

For the years ended December 31,	2004	2003 (Note 2)	2002 (Note 2)
OPERATING ACTIVITIES			
Net earnings	\$ 1,757	\$ 1,650	\$ 955
Items not affecting cash flow from operating activities before changes in non-cash working capital (Note 9)	1,755	1,451	1,020
Exploration expenses (Note 15)	235	271	301
Cash flow from operating activities before changes in non-cash working capital	3,747	3,372	2,276
Proceeds from sale of accounts receivable (Note 11)	399	—	—
(Increase) decrease in other non-cash working capital related to operating activities (Note 10)	133	(164)	(226)
Cash flow from operating activities	4,279	3,208	2,050
INVESTING ACTIVITIES			
Expenditures on property, plant and equipment and exploration (Note 15)	(4,073)	(2,315)	(1,861)
Proceeds from sales of assets	44	165	26
Increase in deferred charges and other assets	(36)	(147)	(72)
Acquisition of Prima Energy Corporation (Note 12)	(644)	—	—
Acquisition of oil and gas operations of Veba Oil & Gas GmbH (Note 12)	—	—	(2,234)
(Increase) decrease in non-cash working capital related to investing activities (Note 10)	10	94	(16)
	(4,699)	(2,203)	(4,157)
FINANCING ACTIVITIES			
Increase in short-term notes payable	314	—	—
Proceeds from issue of long-term debt	533	804	2,100
Repayment of long-term debt	(299)	(1,352)	(465)
Proceeds from issue of common shares	39	50	30
Purchase of common shares (Note 20)	(447)	—	—
Dividends on common shares	(159)	(106)	(105)
Increase in non-cash working capital related to financing activities (Note 10)	(26)	—	—
	(45)	(604)	1,560
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(465)	401	(547)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	635	234	781
CASH AND CASH EQUIVALENTS AT END OF YEAR (Note 13)	\$ 170	\$ 635	\$ 234

Consolidated Balance Sheet

(stated in millions of Canadian dollars)

As at December 31,	2004	2003 (Note 2)
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents (Note 13)	\$ 170	\$ 635
Accounts receivable (Note 11)	1,254	1,503
Inventories (Note 14)	549	551
Prepaid expenses	13	16
	1,986	2,705
PROPERTY, PLANT AND EQUIPMENT, NET (Note 15)	14,783	10,943
GOODWILL (Note 12)	986	810
DEFERRED CHARGES AND OTHER ASSETS (Note 16)	345	316
	\$ 18,100	\$ 14,774
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	\$ 2,223	\$ 1,822
Income taxes payable	370	300
Short-term notes payable	299	—
Current portion of long-term debt (Note 17)	6	6
	2,898	2,128
LONG-TERM DEBT (Note 17)	2,275	2,223
OTHER LIABILITIES (Note 18)	646	306
ASSET RETIREMENT OBLIGATIONS (Note 19)	834	773
FUTURE INCOME TAXES (Note 7)	2,708	1,756
COMMITMENTS AND CONTINGENT LIABILITIES (Note 25)		
SHAREHOLDERS' EQUITY (Note 20)	8,739	7,588
	\$ 18,100	\$ 14,774

Approved on behalf of the Board of Directors



Ron A. Brenneman
Director



Brian F. MacNeill
Director

Notes to Consolidated Financial Statements

(stated in millions of Canadian dollars, unless otherwise stated)

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The Consolidated Financial Statements include the accounts of Petro-Canada and of all subsidiary companies (the Company) and are prepared in accordance with Canadian generally accepted accounting principles (GAAP). Differences between Canadian and United States GAAP are explained in Note 26 to the Consolidated Financial Statements.

Substantially all of the Company's exploration and development activities are conducted jointly with others. Only the Company's proportionate interest in such activities is reflected in the Consolidated Financial Statements.

The preparation of the Consolidated Financial Statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates used in the preparation of the financial statements include, but are not limited to, the estimates of oil and gas reserves, asset retirement obligations, income taxes and employee future benefits.

(b) Revenue Recognition

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer. Inter-segment sales are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer; these amounts are eliminated on consolidation.

International operations conducted pursuant to exploration and production-sharing agreements (EPSAs) are reflected in the Consolidated Financial Statements based on the Company's working interest in such operations. Under the EPSAs, the Company and other non-governmental partners pay all operating and capital costs for exploring and developing the concessions. Each EPSA establishes specific terms for the Company to recover these costs (Cost Recovery Oil) in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year and to share in the production profits (Profit Oil). Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners and the government of each country, varying with the level of production. Profit Oil that is attributable to the government includes an amount in respect of all deemed income taxes payable by the Company under the laws of the respective country. All other government stakes, other than income taxes, are considered to be royalty interests.

(c) Foreign Currency Translation

Monetary assets and liabilities are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. With the exception of items pertaining to self-sustaining operations, the other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expense items are translated into Canadian dollars at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings.

The Company's International business segment and the U.S. Rockies upstream operations included in the North American Natural Gas business segment are operated on a self-sustaining basis. Assets and liabilities of these segments, including associated long-term debt, are translated into Canadian dollars at period end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the foreign currency translation adjustment as part of shareholders' equity.

(d) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income taxes are recognized, using substantively enacted income tax rates, based on the differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in income in the period the change occurs.

(e) Earnings Per Share

Basic earnings per share are calculated by dividing the net earnings available to common shareholders by the weighted-average number of common shares outstanding. Diluted earnings per share reflect the potential dilution that would occur if stock options, excluding stock options with a cash payment alternative, were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options would be used to purchase common shares at the average market price for the period.

(f) Cash and Cash Equivalents

Cash and cash equivalents comprise cash in banks, less outstanding cheques, and short-term investments with a maturity of less than 90 days when purchased. Short-term investments are recorded at the lower of cost or market value.

(g) Sale of Accounts Receivable

The transfers of accounts receivable are accounted for as sales, other than the retained interest, when the Company has surrendered control over the transferred receivables and received proceeds. Gains or losses are recognized as other income or expenses and are dependent upon the purchase discount as well as the previous carrying amount of the receivables transferred, which is allocated between the receivables sold and the retained interest, based on their relative fair values at the date of the transfer. Fair value is determined based on the present value of future expected cash flows.

(h) Inventories

Inventories are stated at the lower of cost and net realizable value. Cost of crude oil and product purchases is determined primarily on a "last-in, first-out" (LIFO) basis.

(i) Investments

Investments in companies over which the Company has significant influence are accounted for using the equity method. Other long-term investments are accounted for using the cost method.

(j) Property, Plant and Equipment

Investments in exploration and development activities are accounted for using the successful efforts method. Under this method, the acquisition cost of unproved acreage is capitalized. Costs of exploratory wells are initially capitalized pending determination of proved reserves. Costs of wells which are assigned proved reserves remain capitalized, while costs of unsuccessful wells are charged to earnings. All other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

The interest cost of debt attributable to the construction of major new facilities is capitalized during the construction period.

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset. If required, the impairment recorded is the amount by which the carrying value of the asset exceeds its fair value.

(k) Depreciation, Depletion and Amortization

Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit of production method.

Depreciation of other plant and equipment is provided on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate.

Deferred financing costs are amortized over the term of the related liability.

Costs associated with significant development projects are not depleted until commencement of commercial production.

(l) Asset Retirement Obligations

The fair values of estimated asset retirement obligations are recorded as liabilities when incurred and the associated cost is capitalized as part of the cost of the related asset. Over time, the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets. The associated accretion is recorded in operating expense and the depreciation is included in depreciation, depletion and amortization expense.

Asset retirement obligations for Downstream sites are provided when the incurrence is established as a result of a legal obligation to restore the site or when the Company intends to restore the site.

Asset retirement obligations are not recorded for those assets which have an indeterminate useful life.

(m) Goodwill

Goodwill is the excess purchase price over the fair value of identifiable assets and liabilities acquired. Goodwill impairment is assessed annually at year end, or more frequently as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

(n) Stock-Based Compensation

The Company maintains stock option, performance share unit and deferred stock unit plans as described in Note 21 to the Consolidated Financial Statements.

The Company accounts for stock options granted prior to 2003 based on the intrinsic value at the grant date, which does not result in a charge to earnings because the exercise price was equal to the market price at grant date.

Stock options granted in 2003 are accounted for using the fair value method. Fair values are determined, at the grant date, using the Black-Scholes option pricing model. The compensation expense associated with these options is charged to earnings over the vesting period with a corresponding increase in contributed surplus. On the exercise of stock options, consideration paid and the associated contributed surplus is credited to common shares.

Stock options granted subsequent to 2003, which provide the holder with a cash payment alternative, are accounted for based on the intrinsic value at each period end whereby a liability and expense are recorded over the vesting period in the amount by which the then current market price exceeds the option exercise price.

Performance share units (PSUs) are accounted for on a mark-to-market basis over the term of the PSUs whereby a liability and expense are recorded based on the number of PSUs outstanding, the current market price of the Company's shares and the Company's current total shareholder return relative to the selected industry peer group.

Deferred stock units (DSUs) are accounted for on a mark-to-market basis whereby a liability and expense are recorded each period based on the number of DSUs outstanding and the current market price of the Company's shares.

(o) Employee Future Benefits

The Company's employee future benefit programs consist of both defined benefit and defined contribution pension plans, as well as other post-retirement benefits as described in Note 22 to the Consolidated Financial Statements.

The Company records its obligations under employee benefit plans, net of plan assets where applicable. The costs of pensions and other post-retirement benefits are actuarially determined using the projected benefit method pro rated based on service and using management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. For the purpose of calculating the expected return on plan assets, those assets are measured at fair value. The accrued benefit obligation is discounted using a market rate of interest at the beginning of the year on high quality corporate debt instruments. Company contributions to the defined contribution plan are expensed as incurred.

(p) Hedging and Derivative Financial Instruments

The Company may use derivative financial instruments to manage its exposure to market risks resulting from fluctuations in foreign exchange rates, interest rates and commodity prices. These derivative financial instruments are not used for speculative purposes and a system of controls is maintained that includes a policy covering the authorization, reporting and monitoring of derivative activity.

The Company formally documents all derivative instruments designated as hedges, the risk management objective, and the strategy for undertaking the hedge.

Gains and losses on derivatives that are designated as and determined to be effective hedges are deferred and recognized in the period of settlement as a component of the related transaction. The Company assesses both at inception and over the term of the hedging relationship, whether the derivative instruments used in the hedging transactions are highly effective in offsetting changes in the fair value or cash flows of hedged items. If a derivative instrument ceases to be effective or is terminated, hedge accounting is discontinued. The accumulated gains and losses continue to be deferred and recognized in the Consolidated Statement of Earnings in the period of settlement of the related transaction; future gains or losses are recognized in the Consolidated Statement of Earnings in the period they occur.

Derivative instruments that are not designated as hedges for accounting purposes are recorded on the Consolidated Balance Sheet at fair value with any resulting gain or loss recognized in the Consolidated Statement of Earnings in the current period.

Asset Retirement Obligations

Effective January 1, 2004, the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants (CICA) on accounting for asset retirement obligations. The new standard requires the fair values of asset retirement obligations to be recorded as liabilities when incurred and the related assets be increased by the amount of these liabilities. Over time, the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets. Asset retirement obligations are not recorded for those assets which have an indeterminate useful life. The change results in a decrease in net earnings of \$4 million for the year ended December 31, 2004 (decrease in net earnings of \$19 million for the year ended December 31, 2003 and \$19 million for the year ended December 31, 2002). The change also resulted, at December 31, 2004, in an increase in asset retirement obligations of \$403 million (increase of \$391 million as at December 31, 2003), an increase in property, plant and equipment of \$189 million (increase of \$184 million as at December 31, 2003), a decrease in retained earnings of \$137 million (decrease of \$133 million as at December 31, 2003) and a decrease in future income taxes of \$77 million (decrease of \$74 million as at December 31, 2003).

Reclassification of Costs

Pursuant to the new CICA section 1100 "Generally Accepted Accounting Principles," which provides guidance on the sources to consult when selecting accounting policies, the Company began accounting, effective January 1, 2004, for certain transportation costs, third-party gas purchases and diluent purchases as expenses in the Consolidated Statement of Earnings. Previously, these costs were netted against revenue. Prior years' comparatives have been restated. The change in accounting has no effect on net earnings but has increased revenue and expenses as follows:

	2004	2003	2002
Operating revenue	\$ 801	\$ 678	\$ 457
Crude oil and product purchases	650	522	281
Operating, marketing and general	151	156	176
Net earnings	\$ –	\$ –	\$ –

Hedging Relationships

Effective January 1, 2004, the Company adopted Accounting Guideline 13 (AcG 13) "Hedging Relationships" which resulted in changes to the conditions as to when hedge accounting may be obtained. As a result, certain of the Company's risk management derivative instruments no longer qualify as accounting hedges and are accounted for as required under Emerging Issues Committee (EIC) 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments." EIC 128 requires that all derivative instruments that do not qualify or are not designated as a hedge under AcG 13 be recorded on the balance sheet at fair value as either an asset or liability with changes in fair value recognized in earnings (see Note 23 to the Consolidated Financial Statements).

Employee Future Benefits

The Company has adopted the amendments made to CICA handbook section 3461, "Employee Future Benefits." The amendments require additional disclosures (see Note 22 to the Consolidated Financial Statements) and have no effect on the financial results of the Company.

Note 3 **SEGMENTED INFORMATION**

The Company is an integrated oil and gas company with a portfolio of businesses spanning both the upstream and downstream sectors of the industry. The Company conducts its business through five major operating business segments along with Shared Services. Upstream activities are conducted through four business segments, which include North American Natural Gas, East Coast Oil, Oil Sands and International; Downstream operations comprise the fifth business segment.

Upstream operations include the exploration, development, production, transportation and marketing activities for crude oil, natural gas and natural gas liquids and oil sands. The North American Natural Gas segment includes activity in Western Canada, the U.S. Rockies, the Mackenzie Delta/Corridor, Offshore Nova Scotia and Alaska. The East Coast Oil segment comprises activity Offshore Newfoundland and Labrador, and includes interests in the Hibernia and Terra Nova oilfield operations as well as an interest in the White Rose oilfield currently under development. The Oil Sands segment includes an

	UPSTREAM								
	NORTH AMERICAN NATURAL GAS			EAST COAST OIL			OIL SANDS		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
Revenue ^{1,2}									
Sales to customers and other revenues	\$ 1,773	\$ 1,756	\$ 1,185	\$ 911	\$ 817	\$ 618	\$ 412	\$ 235	\$ 8
Inter-segment sales	215	190	183	527	482	379	548	391	406
Segment revenue	1,988	1,946	1,368	1,438	1,299	997	960	626	414
Expenses									
Crude oil and product purchases	359	366	278	—	—	—	291	156	3
Inter-segment transactions	9	7	3	5	—	—	49	36	—
Operating, marketing and general	379	330	309	120	121	141	362	332	245
Exploration	119	146	206	2	47	17	16	23	23
Depreciation, depletion and amortization	321	269	264	268	267	225	69	179	30
Foreign currency translation	—	—	—	—	—	—	—	—	—
Interest	—	—	—	—	—	—	—	—	—
	1,187	1,118	1,060	395	435	383	787	726	301
Earnings before income taxes	801	828	308	1,043	864	614	173	(100)	113
Provision for income taxes									
Current	330	227	268	323	313	172	(71)	(20)	(26)
Future	(29)	109	(128)	9	(46)	14	124	(28)	61
	301	336	140	332	267	186	53	(48)	35
Net earnings	\$ 500	\$ 492	\$ 168	\$ 711	\$ 597	\$ 428	\$ 120	\$ (52)	\$ 78
Capital and exploration expenditures									
Property, plant and equipment and exploration expenditures	\$ 724	\$ 560	\$ 530	\$ 278	\$ 344	\$ 289	\$ 399	\$ 448	\$ 462
Deferred charges and other assets	6	4	(3)	1	4	—	—	—	—
Acquisition of oil and gas operations of Veba Oil & Gas GmbH, including goodwill	—	—	—	—	—	—	—	—	—
Acquisition of Prima Energy Corporation, including goodwill	644	—	—	—	—	—	—	—	—
	\$ 1,374	\$ 564	\$ 527	\$ 279	\$ 348	\$ 289	\$ 399	\$ 448	\$ 462
Cash flow from operating activities before changes in non-cash working capital	\$ 940	\$ 985	\$ 534	\$ 996	\$ 869	\$ 687	\$ 334	\$ 127	\$ 196
Total assets ³	\$ 3,477	\$ 2,341	\$ 2,285	\$ 2,265	\$ 2,288	\$ 2,249	\$ 1,883	\$ 1,770	\$ 1,498

interest in the Syncrude oil sands mining operation as well as the MacKay River *in situ* oil sands operation. The International segment includes activity primarily in the United Kingdom (U.K.), The Netherlands, Trinidad, Venezuela, Syria, Libya, Algeria and Tunisia.

The Downstream business segment includes the purchase and sale of crude oil, the refining of crude oil products and the distribution and marketing of these and other purchased products.

Financial information by business segment is presented in the following table as though each segment were a separate business entity. Inter-segment transfers of products, which are accounted for at market value, are eliminated on consolidation. Shared Services includes investment income, interest expense, foreign currency translation and general corporate revenue and expense. Shared Services assets are principally cash and cash equivalents and other general corporate assets.

	INTERNATIONAL			DOWNSTREAM			SHARED SERVICES			CONSOLIDATED		
	2004	2003	2002	2004	2003	2002	2004	2003	2002	2004	2003	2002
	\$ 1,851	\$ 1,945	\$ 1,239	\$ 9,420	\$ 8,145	\$ 7,318	\$ 10	\$ 1	\$ 6	\$ 14,377	\$ 12,899	\$ 10,374
	—	—	—	14	7	3	—	—	—			
	1,851	1,945	1,239	9,434	8,152	7,321	10	1	6	14,377	12,899	10,374
	—	—	—	6,093	5,099	4,556	(3)	(1)	—	6,740	5,620	4,837
	—	—	—	1,241	1,027	968	—	—	—			
	437	407	288	1,328	1,293	1,179	64	74	60	2,690	2,557	2,222
	98	55	55	—	—	—	—	—	—	235	271	301
	466	444	249	277	400	208	1	1	1	1,402	1,560	977
	—	—	—	—	—	—	(77)	(251)	52	(77)	(251)	52
	—	—	—	—	—	—	142	182	187	142	182	187
	1,001	906	592	8,939	7,819	6,911	127	5	300	11,132	9,939	8,576
	850	1,039	647	495	333	410	(117)	(4)	(294)	3,245	2,960	1,798
	727	644	413	226	204	242	(74)	(121)	(110)	1,461	1,247	959
	(52)	88	9	(45)	(119)	(84)	20	59	12	27	63	(116)
	675	732	422	181	85	158	(54)	(62)	(98)	1,488	1,310	843
	\$ 175	\$ 307	\$ 225	\$ 314	\$ 248	\$ 252	\$ (63)	\$ 58	\$ (196)	\$ 1,757	\$ 1,650	\$ 955
	\$ 1,824	\$ 525	\$ 221	\$ 839	\$ 424	\$ 344	\$ 9	\$ 14	\$ 15	\$ 4,073	\$ 2,315	\$ 1,861
	—	—	—	26	53	27	3	86	48	36	147	72
	—	—	2,234	—	—	—	—	—	—	—	—	2,234
	—	—	—	—	—	—	—	—	—	644	—	—
	\$ 1,824	\$ 525	\$ 2,455	\$ 865	\$ 477	\$ 371	\$ 12	\$ 100	\$ 63	\$ 4,753	\$ 2,462	\$ 4,167
	\$ 1,027	\$ 890	\$ 583	\$ 556	\$ 601	\$ 380	\$ (106)	\$ (100)	\$ (104)	\$ 3,747	\$ 3,372	\$ 2,276
	\$ 5,954	\$ 3,973	\$ 3,544	\$ 4,462	\$ 3,827	\$ 3,836	\$ 59	\$ 575	\$ 132	\$ 18,100	\$ 14,774	\$ 13,544

1 There were no customers that represented 10% or more of the Company's consolidated revenues for the periods presented.

2 North American Natural Gas revenue for 2004 includes \$54 million (2003 – nil; 2002 – nil) attributable to the U.S. Rockies operations.

3 North American Natural Gas assets include \$919 million (2003 – \$6 million; 2002 – \$7 million) attributable to the U.S. Rockies and Alaska operations.

Note 4 INVESTMENT AND OTHER INCOME

Investment and other income includes \$329 million (2003 – nil; 2002 – nil) for unrealized losses on derivative contracts, of which \$333 million (2003 – nil; 2002 – nil) relates to the outstanding Buzzard derivative contracts (see Note 23 to the Consolidated Financial Statements), and \$12 million (2003 – \$42 million; 2002 – \$(2) million) for net gains (losses) on disposal of assets.

Note 5 ASSET WRITEDOWNS

Following a review of its Eastern Canada refining and supply operations, Petro-Canada announced in September 2003 it would be ceasing its Oakville refining operations and expanding the existing terminalling facilities. The total charge to earnings related to the shutdown, which is now expected to occur in the first half of 2005, is approximately \$200 million after-tax. The following expenses have been recorded in the Downstream segment:

	2004		2003	
	Pre-Tax	After-Tax	Pre-Tax	After-Tax
Operating, marketing and general expense (de-commissioning and employee related costs)	\$ 3	\$ 2	\$ 54	\$ 32
Depreciation and amortization expense (asset writedowns and increased depreciation)	71	44	196	119
	\$ 74	\$ 46	\$ 250	\$ 151

Depreciation, depletion and amortization expense for the year ended December 31, 2003 also includes \$136 million (\$82 million after-tax) relating mainly to engineering costs incurred in finalizing the Company's strategy for converting the Edmonton refinery to process an oil sands feedstock and charges of \$46 million (\$46 million after-tax) relating to the impairment of assets in Kazakhstan. The charges were recorded in the Oil Sands and International business segments respectively.

Note 6 FOREIGN CURRENCY TRANSLATION

Foreign currency translation consists of:

	2004	2003	2002
Gain on translation of foreign currency denominated long-term debt ¹	\$ (77)	\$ (251)	\$ (11)
Loss on translation of International business segment ²	–	–	63
	\$ (77)	\$ (251)	\$ 52

¹ Gains or losses on foreign currency denominated long-term debt associated with the self-sustaining International business segment and the U.S. Rockies operations included in the North American Natural Gas business segment are deferred and included as part of shareholders' equity.

² Prior to 2003, the International business segment did not operate on a self-sustaining basis. Gains and losses from translation of its financial statements and associated long-term debt into Canadian dollars were included in the Consolidated Statement of Earnings.

Note 7 INCOME TAXES

The computation of the provision for income taxes, which requires adjustment to earnings before income taxes for non-taxable and non-deductible items, is as follows:

	2004	2003	2002
Earnings before income taxes	\$ 3,245	\$ 2,960	\$ 1,798
Add (deduct):			
Non-deductible royalties and other payments to provincial governments, net	352	392	277
Resource allowance	(512)	(542)	(467)
Equity in earnings of affiliates	(15)	(11)	(9)
Non-taxable foreign exchange	(40)	(237)	52
Other	5	28	(3)
Earnings as adjusted before income taxes	\$ 3,035	\$ 2,590	\$ 1,648
Canadian Federal income tax rate	38.0%	38.0%	38.0%
Income tax on earnings as adjusted at Canadian			
Federal income tax rate	\$ 1,153	\$ 984	\$ 626
Large Corporations Tax	17	16	16
Provincial income taxes	271	194	130
Federal – abatement and other credits	(274)	(167)	(102)
Future income taxes (decrease) increase due to federal and provincial rate changes	(13)	(45)	4
Higher foreign income tax rates	357	337	176
Income tax credits and other	(23)	(9)	(7)
Provision for income taxes	\$ 1,488	\$ 1,310	\$ 843
Effective income tax rate on earnings before income taxes	45.9%	44.3%	46.9%

Future income taxes consists of the following future income tax liabilities (assets) relating to temporary differences for:

	2004	2003
Property, plant and equipment	\$ 2,961	\$ 2,010
Partnership income ¹	404	381
Inventories	(184)	(134)
Asset retirement obligations and other liabilities	(318)	(333)
Deferred charges and other assets	55	43
Resource allowance and other	(210)	(211)
	\$ 2,708	\$ 1,756

¹ Taxable income for certain Canadian upstream activities are generated by a partnership and the related taxes will be included in current income taxes in the next year.

Deferred distribution taxes associated with International business operations have not been recorded. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional tax expense.

Complex income tax issues, which involve interpretations of continually changing regulations, are encountered in computing the provision for income taxes. Management believes that adequate provision has been made for all such outstanding issues and that the resolution of these issues would not materially affect the financial position of the Company.

Note 8 **EARNINGS PER SHARE**

The weighted-average number of common shares outstanding used in the calculation of basic earnings per share and diluted earnings per share, assuming that all dilutive outstanding stock options were exercised, was:

	2004	2003	2002
Average shares outstanding (millions)			
Basic	264.6	264.9	262.8
Diluted	268.1	267.9	265.7

For the year ended December 31, 2004, no stock options (2003 – nil stock options; 2002 – 375,700 stock options with an exercise price of \$45.68) were excluded from the diluted earnings per share calculation. Stock options are excluded when the exercise price exceeds the average share price in a respective period. The average share price in 2002 was \$42.70.

Note 9 **ITEMS NOT AFFECTING CASH FLOW FROM OPERATING ACTIVITIES
BEFORE CHANGES IN NON-CASH WORKING CAPITAL**

	2004	2003	2002
Depreciation, depletion and amortization	\$ 1,402	\$ 1,560	\$ 977
Future income taxes	27	63	(116)
Accretion of asset retirement obligations	50	64	37
Unrealized gain on translation of foreign currency denominated long-term debt	(77)	(251)	(11)
(Gain) loss on disposal of assets	(12)	(42)	2
Amortization of debt issue costs	6	22	14
Unrealized loss associated with the Buzzard derivative contracts	333	—	—
Unrealized foreign currency losses	—	—	90
Other	26	35	27
	\$ 1,755	\$ 1,451	\$ 1,020

Note 10 **(INCREASE) DECREASE IN NON-CASH WORKING CAPITAL**

	2004	2003	2002
Operating activities			
Accounts receivable	\$ (88)	\$ 93	\$ (268)
Inventories	4	34	(74)
Prepaid expenses	6	3	9
Accounts payable and accrued liabilities	247	(219)	467
Income taxes payable	71	37	(313)
Current portion of long-term liabilities and other	(107)	(112)	(47)
	\$ 133	\$ (164)	\$ (226)
Investing activities			
Accounts payable and accrued liabilities	\$ 10	\$ 94	\$ (16)
Financing activities			
Accounts payable and accrued liabilities	\$ (26)	\$ —	\$ —

Non-cash working capital is comprised of current assets and current liabilities, other than cash and cash equivalents and the current portion of long-term debt.

Note 11 SECURITIZATION PROGRAM

In June 2004, the Company entered into a securitization program, expiring in 2009, to sell an undivided interest of eligible accounts receivable up to \$400 million to a third party, on a revolving and fully serviced basis. The service liability has been estimated to be insignificant. The Company also retains an interest in the transferred accounts receivable equal to the required reserves amount.

The Company accounts for the securitization program as a sale, as control over the transferred accounts receivable is relinquished once proceeds from the third party have been received. Gains or losses from the sale are recognized in investment and other income.

As at December 31, 2004, \$400 million of outstanding accounts receivable had been sold under the program for net proceeds of \$399 million.

Note 12 BUSINESS ACQUISITIONS

Prima Energy Corporation

On July 28, 2004, the Company acquired all of the common shares of Prima Energy Corporation (Prima), an oil and gas company with operations in the U.S. Rockies, for a total acquisition cost of \$644 million, net of cash acquired. The results of operations are included in the Consolidated Financial Statements from the date of acquisition. Funding for the acquisition was provided by a \$400 million US underwritten credit facility, cash and cash equivalents and existing committed bank credit lines.

Veba Oil & Gas GmbH

On May 2, 2002, the Company acquired the shares of companies holding the majority of the international oil and gas operations of Veba Oil & Gas GmbH (Veba) and on December 10, 2002, the Company acquired certain of the remaining operations which were subject to rights of first refusal. The total acquisition cost, consisting of cash consideration and acquisition costs, was \$2,234 million and the results of these operations have been included in the Consolidated Financial Statements from the dates of acquisition. Funds for the acquisition were provided from credit facilities arranged with certain banks and from cash and cash equivalents.

Both acquisitions were accounted for by the purchase method of accounting. The allocations of fair values to the assets acquired and liabilities assumed were:

	2004 <i>Prima</i>	2002 <i>Veba</i>
Property, plant and equipment	\$ 688	\$ 2,012
Goodwill	193	709
Current assets ¹	36	640
Deferred charges and other assets	2	6
Total assets acquired	919	3,367
Current liabilities	41	634
Future income taxes	217	387
Asset retirement obligations and other liabilities	17	112
Total liabilities assumed	275	1,133
Net assets acquired	\$ 644	\$ 2,234

¹ Current assets exclude cash of \$74 million for Prima and \$15 million for Veba.

Goodwill, which is not tax deductible, was assigned to the Company's North American Natural Gas business segment for Prima and to the Company's International business segment for Veba.

Note 13 CASH AND CASH EQUIVALENTS

	2004	2003
Cash	\$ 169	\$ 60
Less: outstanding cheques	(65)	(39)
	104	21
Short-term investments	66	614
	\$ 170	\$ 635

Cash payments for interest and income taxes were as follows:

	2004	2003	2002
Interest	\$ 165	\$ 156	\$ 178
Income taxes	\$ 1,477	\$ 1,232	\$ 1,172

Note 14 INVENTORIES

	2004	2003
Crude oil, refined products and merchandise	\$ 383	\$ 394
Materials and supplies	166	157
	\$ 549	\$ 551

Note 15 PROPERTY, PLANT AND EQUIPMENT

	2004			2003			2004	2003
	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Expenditures on Property, Plant and Equipment ^{1,2}	
Upstream								
North American Natural Gas	\$ 5,521	\$ 2,491	\$ 3,030	\$ 4,299	\$ 2,184	\$ 2,115	\$ 605	\$ 414
East Coast Oil	3,274	1,094	2,180	2,993	837	2,156	276	297
Oil Sands	2,417	628	1,789	2,218	568	1,650	383	425
International	5,471	1,011	4,460	2,988	549	2,439	1,726	470
	16,683	5,224	11,459	12,498	4,138	8,360	2,990	1,606
Downstream								
Refining	3,372	1,220	2,152	3,178	1,690	1,488	662	303
Marketing and other	2,358	1,218	1,140	2,284	1,225	1,059	177	121
	5,730	2,438	3,292	5,462	2,915	2,547	839	424
Other property, plant and equipment								
	458	426	32	449	413	36	9	14
	\$ 22,871	\$ 8,088	\$ 14,783	\$ 18,409	\$ 7,466	\$ 10,943	\$ 3,838	\$ 2,044

1 Exploration expenses of \$235 million (2003 – \$271 million; 2002 – \$301 million) charged to earnings are reclassified from operating activities and included with expenditures on property, plant and equipment and exploration under investing activities in the Consolidated Statement of Cash Flows.

2 Expenditures on property, plant and equipment and exploration for the year ended December 31, 2004 include the Company's purchase of a 29.9% interest in the Buzzard field and nearby exploration blocks in the U.K. sector of the North Sea for \$1,218 million (\$887 million US), net of cash received.

Property, plant and equipment net cost includes asset retirement costs of \$297 million (2003 – \$292 million).

Interest capitalized during 2004 amounted to \$20 million (2003 – \$7 million; 2002 – \$4 million).

Costs of \$577 million (2003 – \$422 million) relating to non-producing East Coast Oil projects, \$2,587 million (2003 – \$314 million) relating to the International operations and \$338 million (2003 – nil) relating to U.S. Rockies operations are currently not being depleted.

Capital leases at a net cost of \$67 million (2003 – \$70 million) and \$27 million (2003 – \$29 million) are included in the assets of East Coast Oil and Oil Sands, respectively (see Note 17 to the Consolidated Financial Statements).

Note 16 DEFERRED CHARGES AND OTHER ASSETS

	2004	2003
Investments	\$ 78	\$ 72
Deferred pension funding	71	49
Deferred financing costs	98	97
Other long-term assets	98	98
	\$ 345	\$ 316

Note 17 LONG-TERM DEBT

	Maturity	2004	2003
Debentures and notes			
5.35% unsecured senior notes ¹ (\$300 million US)	2033	\$ 361	\$ 388
7.00% unsecured debentures (\$250 million US)	2028	301	323
7.875% unsecured debentures (\$275 million US)	2026	331	355
9.25% unsecured debentures (\$300 million US)	2021	361	388
5.00% unsecured senior notes ² (\$400 million US)	2014	481	—
4.00% unsecured senior notes ¹ (\$300 million US)	2013	361	388
Capital leases (Note 15) ³	2007-2017	85	94
Acquisition credit facilities ⁴	2005	—	293
		2,281	2,229
Current portion		(6)	(6)
		\$ 2,275	\$ 2,223

1 In anticipation of issuing these senior notes, the Company entered into interest rate derivatives which resulted in effective interest rates of 6.073% for the 5.35% notes due in 2033 and 4.838% for the 4.00% notes due in 2013.

2 The Company established a \$400 million US underwritten credit facility to partially fund the acquisition of Prima Energy Corporation (see Note 12 to the Consolidated Financial Statements). On November 8, 2004, the Company issued these senior notes, the proceeds of which were used to repay the credit facility.

3 The Company is party to a transportation agreement to transport bitumen from the MacKay River production facilities to the Athabasca Pipeline Terminal. The agreement is for an initial term of 15 years ending in 2017 and is extendable at the Company's option for an additional 10 years.

The Company is party to an agreement for the time charter and operation of a vessel for the transportation of East Coast Oil crude oil production. The agreement is for an initial term of 10 years ending in 2007 and extendable at the Company's option for up to an additional 15 years.

The transportation and time charter agreements are accounted for as capital leases and have implicit rates of interest of 14.65% and 11.90%, respectively. The aggregate remaining repayments under the transportation and time charter agreements are \$85 million, including the following amounts in the next five years: 2005 – \$6 million; 2006 – \$7 million; 2007 – \$7 million; 2008 – \$2 million; and 2009 – \$3 million.

4 The Company established two unsecured credit facilities with certain banks for the acquisition of the oil and gas operations of Veba Oil & Gas GmbH (see Note 12 to the Consolidated Financial Statements). The credit facilities totaled \$3,320 million, of which \$2,100 million was drawn in the form of floating rate Canadian dollar bankers' acceptances in 2002. At December 31, 2003, the amount of the facilities was \$743 million, of which \$293 million was outstanding. During 2004, the Company sold \$400 million under a new accounts receivable securitization program (see Note 11 to the Consolidated Financial Statements) and a portion of the proceeds was used to repay the remaining \$293 million of advances.

Interest on long-term debt, net of capitalized interest, was \$132 million in 2004 (2003 – \$177 million; 2002 – \$182 million).

The Company's syndicated operating credit facilities totaled \$1,500 million to be used for general corporate purposes.

Note 18 OTHER LIABILITIES

	2004	2003
Post-retirement benefits	\$ 164	\$ 153
Unrealized loss on Buzzard derivative contracts	333	—
Other long-term liabilities	149	153
	\$ 646	\$ 306

Note 19 ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations are recorded for obligations where the Company will be required to retire tangible long-lived assets such as well sites, offshore production platforms, natural gas processing plants and marketing sites. Obligations are currently not recorded for assets, principally refineries, upgrading assets and certain gas plants, which have an indeterminate life.

The following table summarizes the changes in the asset retirement obligations:

	2004	2003
Asset retirement obligations at beginning of year	\$ 773	\$ 642
Obligations incurred	67	97
Abandonment expenditures	(44)	(33)
Accretion expense	50	64
Other	(12)	3
Asset retirement obligations at end of year	\$ 834	\$ 773

In determining the fair value of the asset retirement obligations, the estimated cash flows have been discounted at 6.5%. The total undiscounted amount of the estimated cash flows required to settle the obligations is \$2,417 million (2003 – \$2,121 million). The obligations will be settled on an ongoing basis over the useful lives of the operating assets, which extend up to 45 years in the future.

Note 20 SHAREHOLDERS' EQUITY

	2004	2003
Common shares	\$ 1,314	\$ 1,308
Contributed surplus	1,743	2,147
Retained earnings	5,408	3,810
Foreign currency translation adjustment	274	323
	\$ 8,739	\$ 7,588

The authorized share capital is comprised of an unlimited number of:

- (a) Preferred shares issuable in series designated as Senior Preferred Shares.
- (b) Preferred shares issuable in series designated as Junior Preferred Shares.
- (c) Common shares.

Changes in common shares and contributed surplus were as follows:

	2004			2003		
	Shares	Amount	Contributed Surplus	Shares	Amount	Contributed Surplus
Balance at beginning of year	265,586,093	\$ 1,308	\$ 2,147	263,594,977	\$ 1,258	\$ 2,138
Issued for cash under employee stock option and share purchase plans	1,246,000	39	–	1,991,116	50	–
Repurchases of common shares	(6,868,082)	(34)	(413)	–	–	–
Stock-based compensation	–	1	9	–	–	9
Balance at end of year	259,964,011	\$ 1,314	\$ 1,743	265,586,093	\$ 1,308	\$ 2,147

Under the terms of a normal course issuer bid (NCIB), the Company is entitled to purchase up to 21 million of its common shares during the period from June 22, 2004 to June 21, 2005, subject to certain conditions. During 2004, the Company repurchased 6,868,082 common shares under the NCIB at an average price of \$65.02 per common share for a total cost of approximately \$447 million. The excess of purchase cost over the carrying amount of the shares purchased was recorded as a reduction of contributed surplus.

Stock Options

The Company maintains a stock option plan whereby options can be granted to officers and certain employees for up to 22 million common shares. Stock options have a term of 10 years if granted prior to 2004 and seven years if granted subsequent to 2003. All stock options vest over periods of up to four years and are exercisable at the market prices for the shares on the dates that the options were granted.

During 2004, the Company amended the option plan to provide the holder of stock options granted subsequent to 2003 the alternative to exercise these options as a cash payment alternative (CPA). Where the CPA is chosen, vested options can be surrendered for cancellation in return for a direct cash payment from the Company based on the excess of the then market price over the option exercise price.

Changes in the number of outstanding stock options were as follows:

	2004		2003		2002	
	Weighted-Average Exercise Price		Weighted-Average Exercise Price		Weighted-Average Exercise Price	
	Number	(dollars)	Number	(dollars)	Number	(dollars)
Balance at beginning of year	8,620,593	\$ 37	8,225,984	\$ 30	7,216,770	\$ 26
Granted	1,836,700	58	2,481,000	51	2,482,700	36
Exercised	(1,246,000)	31	(1,991,116)	25	(1,403,936)	22
Cancelled	(173,944)	45	(95,275)	41	(69,550)	30
Balance at end of year	9,037,349	\$ 42	8,620,593	\$ 37	8,225,984	\$ 30

The following stock options were outstanding as at December 31, 2004:

Options Outstanding				Options Exercisable	
Number	Range of Exercise Prices (dollars)	Weighted-Average Life (years)	Weighted-Average Exercise Price (dollars)	Number	Weighted-Average Exercise Price (dollars)
419,677	\$ 11 to 18	1.1	\$ 16	419,677	\$ 16
758,925	19 to 25	4.5	21	758,925	21
1,976,832	26 to 35	6.5	33	1,175,957	32
1,850,025	36 to 46	6.3	39	1,305,550	38
2,217,690	47 to 56	8.1	51	554,423	51
1,814,200	57 to 67	6.2	57	—	—
9,037,349	\$ 11 to 67	6.4	\$ 42	4,214,532	\$ 33

During 2004, the Company recorded compensation expense of \$10 million (2003 – \$9 million) relating to the 2003 stock options and \$3 million (2003 – nil) relating to options with a CPA.

The following table presents the pro forma net earnings and the pro forma earnings per share computed assuming the fair value based accounting method had been used to account for the compensation cost of stock options granted in 2002.

	2004	Earnings per Share		2003	Earnings per Share		2002	Earnings per Share	
	Net Earnings	Basic (dollars)	Diluted (dollars)	Net Earnings	Basic (dollars)	Diluted (dollars)	Net Earnings	Basic (dollars)	Diluted (dollars)
Net earnings as reported	\$ 1,757	\$ 6.64	\$ 6.55	\$ 1,650	\$ 6.23	\$ 6.16	\$ 955	\$ 3.63	\$ 3.59
Pro forma adjustment	9	0.03	0.03	8	0.03	0.03	6	0.02	0.02
Pro forma net earnings	\$ 1,748	\$ 6.61	\$ 6.52	\$ 1,642	\$ 6.20	\$ 6.13	\$ 949	\$ 3.61	\$ 3.57

The estimated fair value of stock options granted in 2003, which is charged to earnings, was \$17.50 per share. The estimated weighted-average fair value of stock options granted in 2002, which is incorporated in the pro forma earnings information above, was \$12.74 per share. The fair values have been determined using the Black-Scholes option-pricing model with the following assumptions:

	2003	2002
Risk-free interest rate	4.4%	4.9%
Expected hold period to exercise	6 years	6 years
Volatility in the market price of common shares	32%	33%
Estimated annual dividend	1.4%	1.4%

Performance Share Units

During 2004, the Company implemented a Performance Share Unit (PSU) plan for officers and other senior management employees. Under the PSU program, notional share units are awarded and settled in cash at the end of a three-year period based upon the Company's share price at that time, the value of notional dividends applied during the period and the Company's total shareholder return relative to a peer group of North American industry competitors.

Changes in the number of outstanding PSUs were as follows:

	Number
Balance at beginning of year	—
Granted	284,880
Expired	—
Cancelled	(1,950)
Balance at end of year	282,930

All PSUs outstanding at the end of the year have a performance period ending in 2007. Based on the mark-to-market value at December 31, 2004, no compensation expense relating to PSUs was recorded.

Deferred Share Units

The Company maintains a Deferred Stock Unit (DSU) plan where executive officers can elect to receive all or a portion of their annual incentive compensation in the form of DSUs. Under the officer DSU program, notional share units are issued for the elected amount, which is based on the then current market price of the Company's common shares. Upon termination or retirement, the units are settled in cash which includes an amount for the value of notional dividends earned over the period the units were outstanding.

The Company's Board of Directors receives a portion of their compensation in the form of DSUs and can also elect to receive all or a portion of their non-DSU compensation in the form of DSUs. Under the Director program, notional share units are issued and settled in cash or common shares, including the value of notional dividends, upon ceasing to be a Director.

During 2004, no compensation expense relating to DSUs was recorded (2003 – \$6 million; 2002 – \$3 million).

The Company maintains pension plans with defined benefit and defined contribution provisions, and provides certain health care and life insurance benefits to its qualifying retirees. The actuarially determined cost of these benefits is accrued over the estimated service life of employees. The defined benefit provisions are generally based upon years of service and average salary during the final years of employment. Certain defined benefit options require employee contributions and the balance of the funding for the registered plans is provided by the Company, based upon the advice of an independent actuary. The accrued benefit obligations and the fair value of plan assets are measured for accounting purposes at December 31 of each year. The most recent actuarial valuation of the pension plan for funding purposes was as of December 31, 2002 and the next required valuation will be as of December 31, 2004.

The defined contribution option provides for an annual contribution of 5% to 8% of each participating employee's pensionable earnings.

Benefit Plan Expense	Pension Plans			Other Post-Retirement Plans		
	2004	2003	2002	2004	2003	2002
(a) Defined benefit plans						
Employer current service cost	\$ 31	\$ 27	\$ 25	\$ 4	\$ 4	\$ 3
Interest cost	81	78	74	13	12	11
Actual return on plan assets	(91)	(115)	91	—	—	—
Actuarial losses (gains)	97	99	12	(15)	17	7
Elements of employee future benefit plan expenses before adjustments to recognize the long-term nature of employee future benefit plan expenses	118	89	202	2	33	21
Difference between actual and expected return on plan assets	12	50	(174)	—	—	—
Difference between actual and recognized actuarial losses in year	(67)	(73)	(5)	16	(17)	(7)
Amortization of transitional (asset) obligation	(5)	(5)	(5)	2	2	2
	58	61	18	20	18	16
(b) Defined contribution plans	13	11	10			
Total expense	\$ 71	\$ 72	\$ 28	\$ 20	\$ 18	\$ 16
Benefit Plan Funding						
Defined contribution	\$ 13	\$ 11	\$ 10			
Defined benefit	\$ 80	\$ 75	\$ 12	\$ 9	\$ 8	\$ 7

Financial Status of Defined Benefit Plans	Pension Plans		Other Post-Retirement Plans	
	2004	2003	2004	2003
Fair value of plan assets	\$ 1,157	\$ 1,052	\$ —	\$ —
Accrued benefit obligation	1,487	1,344	204	211
Funded status – plan deficit ¹	(330)	(292)	(204)	(211)
Unamortized transitional (asset) obligation	(29)	(34)	17	19
Unamortized net actuarial losses	430	375	23	39
Accrued benefit asset (liability)	\$ 71	\$ 49	\$ (164)	\$ (153)
Reconciliation of Plan Assets				
Fair value of plan assets at beginning of year	\$ 1,052	\$ 927	\$ —	\$ —
Contributions	80	75	9	8
Benefits paid	(67)	(63)	(9)	(8)
Actual gain (loss) on plan assets	91	115	—	—
Other	1	(2)	—	—
Fair value of plan assets at end of year	\$ 1,157	\$ 1,052	\$ —	\$ —
Reconciliation of Accrued Benefit Obligation				
Accrued benefit obligation at beginning of year	\$ 1,344	\$ 1,206	\$ 211	\$ 186
Current service cost	31	27	4	4
Interest cost	81	78	13	12
Benefits paid	(67)	(63)	(9)	(8)
Actuarial losses (gains)	97	99	(15)	17
Other	1	(3)	—	—
Accrued benefit obligation at end of year	\$ 1,487	\$ 1,344	\$ 204	\$ 211

¹ The pension and other post-retirement plans included in the financial status information are not fully funded.

Defined Benefit and Other Post-Retirement Plans Assumptions	2004	2003	2002
Year-end obligation discount rate ¹	5.7%	6.0%	6.5%
Accrued benefit obligation discount rate ¹	6.0%	6.5%	6.5%
Long-term rate of return on plan assets	7.5%	7.5%	8.0%
Rate of compensation increase, excluding merit increases	3.0%	3.0%	3.0%

¹ Assumption used in both pension and other post-retirement benefit plans.

**Assumed Health and Dental Care Cost Trend Rates
at December 31 are as follows:**

	2004	2003
Dental care cost trend rate ¹	3.5%	3.5%
Health care cost trend rate	8.5%	7.5%
Health care cost trend rate declines to	4.5%	4.5%
Year that health care cost trend rate reaches the rate which it is expected to remain at	2014	2009

¹ Dental care cost trend rate assumed to remain constant.

Sensitivity Analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2004:

	Increase	Decrease
Total of service and interest cost	\$ 2	\$ (2)
Accrued benefit obligation	\$ 24	\$ (22)

The Plan Assets consist of:

Asset Category	Percentage of Plan Assets at December 31,	
	2004	2003
Equity	44%	42%
Bonds	56%	58%
	100%	100%

Note 23 **FINANCIAL INSTRUMENTS AND DERIVATIVES**

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the course of its normal business operations. The Company monitors its exposure to market fluctuations and may use derivative instruments to manage these risks, as it considers appropriate.

Crude Oil and Products

The Company enters into forward contracts and options to reduce exposure to Downstream margin fluctuations, including margins on fixed-price product sales, and short-term price fluctuations on the purchase of foreign and domestic crude oil and refined products.

The Company has also entered into a series of forward sales contracts for the future sale of Brent crude oil in connection with its 2004 acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea (see Note 15 to the Consolidated Financial Statements).

The Company's outstanding contracts for derivative instruments and the related fair values at December 31, 2004 were as follows:

	Quantity	Maturity	Average Price US\$/bbl	Unrealized Gain/(Loss)
Crude Oil and Products <i>(millions of barrels)</i>				
Crude oil purchase	2.7	2005	\$ 40.33	\$ 4
Buzzard crude oil sales	35.8	2007-2010	\$ 25.98	\$ (333)
				\$ (329)

As at December 31, 2004, the unrealized loss on derivative contracts has decreased investment and other income by \$329 million and increased accounts receivable, accounts payable and accrued liabilities, and other liabilities by \$5 million, \$1 million and \$333 million, respectively.

The fair value of these derivative instruments is based on quotes provided by brokers, which represents an approximation of amounts that would be received or paid to counterparties to settle these instruments prior to maturity. The Company plans to hold all derivative instruments outstanding at December 31, 2004 to maturity.

Derivative and financial instruments involve a degree of credit risk. The Company manages this risk through the establishment of credit policies and limits which are applied in the selection of counterparties. Market risk relating to changes in value or settlement cost of the Company's derivative instruments is essentially offset by gains or losses on the hedged positions.

In addition to the derivative instruments described above, the Consolidated Balance Sheet includes other items considered to be financial instruments, such as cash, accounts receivable, accounts payable and accrued liabilities and notes payable. The fair values of these other financial instruments included in the Consolidated Balance Sheet are as follows:

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial instruments included in current assets and current liabilities	\$ (1,098)	\$ (1,098)	\$ 316	\$ 316
Long-term debt	\$ (2,281)	\$ (2,538)	\$ (2,229)	\$ (2,432)

The fair value of financial instruments included in current assets and current liabilities, excluding the current portion of long-term debt, approximates the carrying amount of these instruments due to their short maturity. The fair value of long-term debt is based on publicly quoted market values.

Note 24 **RELATED PARTY TRANSACTIONS**

On September 29, 2004, the Government of Canada completed its offering to the public of its entire remaining interest in Petro-Canada. Transactions with the Government of Canada and its agencies prior to the sale were in the normal course of business and on the same terms as those accorded to non-related parties.

Note 25 **COMMITMENTS AND CONTINGENT LIABILITIES**

(a) The Company has leased property and equipment under various long-term operating leases for periods up to 2013. The minimum annual rentals for non-cancellable operating leases are estimated at \$122 million in 2005, \$102 million in 2006, \$80 million in 2007, \$68 million in 2008, \$61 million in 2009 and \$217 million thereafter.

(b) The Company is involved in litigation and claims in the normal course of operations. In addition, the Company may provide indemnifications, in the course of normal operations, that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid. Management is of the opinion that any resulting settlements relating to the litigation matters or indemnifications would not materially affect the financial position of the Company.

The Company's Consolidated Financial Statements have been prepared in accordance with Canadian GAAP, which differ in some respects from those applicable in the United States. The following are the significant differences in accounting principles as they pertain to the accompanying Consolidated Financial Statements:

(a) Income Taxes

The liability method followed by the Company differs from United States GAAP due to the application of transitional provisions upon adoption, the use of substantively enacted versus enacted tax rates and the accounting for certain Canadian income tax credits and allowances.

(b) Interest Capitalization

United States GAAP requires that interest be capitalized as part of the cost of certain assets while they are being prepared for their intended use. The Company capitalizes interest attributable to the construction of major new facilities and does not capitalize interest on all assets that would require interest capitalization under United States GAAP.

(c) Contributed Surplus

In prior years, the Company transferred amounts from contributed surplus to the accumulated deficit. Under United States GAAP, these transfers would not have occurred.

(d) Derivative Instruments and Hedging

Under United States GAAP, the accounting for derivative instruments and hedging activities is contained in the Statement of Financial Accounting Standards No. 133 (SFAS 133). SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met. The recently amended Canadian rules, Accounting Guideline 13 (AcG 13) "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments" (see Note 2 to the Consolidated Financial Statements), have eliminated the GAAP difference for all derivatives that are not accounted for as hedges for 2004 and future years. A GAAP difference still exists for the treatment of cash flow hedges as changes in the fair value of cash flow hedges are included in other comprehensive income under United States GAAP.

(e) Minimum Pension Liability

United States GAAP requires a minimum pension liability be recorded for underfunded pension plans. The change in the minimum liability, representing the excess of unfunded accumulated benefit obligations over previously recorded pension cost liabilities, is recognized in other comprehensive income.

(f) Comprehensive Income

United States GAAP utilizes the concept of comprehensive income, which includes net earnings and other comprehensive income. The concept of comprehensive income does not yet exist under Canadian GAAP. Other comprehensive income represents the change in equity during the period from transactions and other events from non-owner sources and includes such items as changes in the fair value of cash flow hedges, minimum pension liability adjustments and certain foreign currency translation adjustments.

(g) Asset Retirement Obligations

Under United States GAAP, the accounting for asset retirement obligations is contained in the Statement of Financial Accounting Standards No. 143 (SFAS 143) which was effective January 1, 2003. Changes to the equivalent Canadian accounting standards were effective January 1, 2004 (see Note 2 to the Consolidated Financial Statements) which has eliminated this GAAP difference in 2004 and in future years. Under United States GAAP, the cumulative effect adjustment from initial application is required to be charged to net earnings in the year the standard became effective. Canadian GAAP requires the change in accounting policy be applied retroactively and that prior periods presented for comparative purposes be restated.

The application of United States GAAP would have the following effects on earnings as reported:

	2004	2003	2002
Net earnings as reported in the Consolidated Statement of Earnings	\$ 1,757	\$ 1,650	\$ 955
Adjustments, before income taxes			
Capitalization of interest and related amortization	8	21	25
Accounting for income taxes	(27)	(9)	(111)
Asset retirement obligations	—	—	30
Other	1	—	(3)
Income taxes on above items	9	13	(1)
Net earnings, as adjusted before cumulative effect of change in accounting policy	1,748	1,675	895
Cumulative effect of change in accounting policy, net of income taxes	—	(114)	—
Net earnings, as adjusted	\$ 1,748	\$ 1,561	\$ 895
Earnings, as adjusted before cumulative effect of change in accounting policy per share			
Basic	\$ 6.61	\$ 6.32	\$ 3.41
Diluted	\$ 6.52	\$ 6.25	\$ 3.37
Earnings, as adjusted per share			
Basic	\$ 6.61	\$ 5.89	\$ 3.41
Diluted	\$ 6.52	\$ 5.83	\$ 3.37
Comprehensive income			
Net earnings, as adjusted	\$ 1,748	\$ 1,561	\$ 895
Unrealized gain (loss) on financial derivatives	(5)	8	4
Minimum pension liability	(36)	(11)	(111)
Foreign currency translation adjustment	(49)	323	—
	\$ 1,658	\$ 1,881	\$ 788

The application of United States GAAP would have the following effects on the Consolidated Balance Sheets as reported:

	December 31, 2004		December 31, 2003	
	As Reported	United States GAAP	As Reported	United States GAAP
Current assets	\$ 1,986	\$ 1,986	\$ 2,705	\$ 2,705
Property, plant and equipment, net	14,783	15,337	10,943	11,521
Goodwill	986	965	810	789
Deferred charges and other assets	345	344	316	314
Current liabilities	2,898	2,898	2,128	2,119
Long-term debt	2,275	2,275	2,223	2,223
Other liabilities	646	910	306	436
Asset retirement obligations	834	834	773	773
Future income taxes	2,708	2,894	1,756	2,058
Common shares	1,314	1,314	1,308	1,308
Contributed surplus	1,743	2,865	2,147	3,269
Retained earnings	5,408	4,526	3,810	2,937
Foreign currency translation adjustment	274	—	323	—
Accumulated other comprehensive income	\$ —	\$ 116	\$ —	\$ 206

Canadian

Variable Interest Entities (VIEs)

The Accounting Standards Board (AcSB) issued Accounting Guideline AcG 15, “Consolidation of Variable Interest Entities,” to harmonize the Guideline with the equivalent United States Standard Financial Accounting Standards Board (FASB) Interpretation No. 46R, “Consolidation of Variable Interest Entities.” The Guideline provides criteria for identifying VIEs and further criteria for determining what entity, if any, should consolidate them. The Guideline is effective for annual and interim periods beginning on or after November 1, 2004, and upon adoption, will not materially impact the Consolidated Financial Statements.

Financial Instruments – Disclosure and Presentation

The AcSB approved a revision to section 3860 “Financial Instruments – Disclosure and Presentation,” to require certain obligations that must or could be settled with an entity’s own equity instruments to be represented as liabilities. The revision is effective for fiscal years beginning on or after November 1, 2004. The Company does not expect there to be any impact on the Consolidated Financial Statements upon adoption of this revised standard.

United States

Exchanges of Non-Monetary Assets

The FASB issued Statement of Financial Accounting Standards No. 153 (SFAS 153), “Exchanges of Non-Monetary Assets” as an amendment to Accounting Principles Board Opinion No. 29 (APB 29), “Accounting for Non-Monetary Transactions.” APB 29 prescribes that exchanges of non-monetary transactions should be measured based on the fair value of the assets exchanged, while providing an exception for non-monetary exchanges of similar productive assets. SFAS 153 eliminates the exception provided in APB 29 and replaces it with a general exception for exchanges of non-monetary assets that do not have commercial substance. SFAS 153 is to be applied prospectively and is effective for all non-monetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not expect there to be any material effect on the Consolidated Financial Statements upon adoption of the new standard.

Inventory Costs

The FASB issued SFAS 151, “Inventory Costs” as an amendment to Accounting Research Bulletin No. 43 (ARB 43). Under ARB 43, certain expenses might be considered to be so abnormal that, under certain circumstances, they would require treatment as current period charges. SFAS 151 eliminates the criterion of “so abnormal” and requires that those items be recognized as current period charges. SFAS 151 is to be applied prospectively and is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the standard.

Share-Based Payment

The FASB issued SFAS 123(R), “Share-Based Payment,” a revision to SFAS 123, “Accounting for Stock-Based Compensation.” SFAS 123(R) eliminates the intrinsic value accounting option in APB Opinion 25, “Accounting for Stock Issued to Employees,” and generally requires the use of the fair-value based method of accounting for share based payment transactions with employees. In addition, the standard no longer permits entities to account for forfeitures as they occur but requires this amount to be estimated. SFAS 123(R) is effective for the reporting periods that begin after June 15, 2005 and may be applied under a modified prospective approach or a modified retrospective approach. The Company does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of this revised standard under the modified prospective approach or the modified retrospective approach.

Discontinued Operations

The Emerging Issues Task Force issued EITF Abstract 03-13 (EITF 03-13) to provide guidance on applying SFAS 144, “Determining Whether to Report Discontinued Operations.” SFAS 144 discusses when an entity should disclose a “component” as discontinued operations. Under SFAS 144, a component should be disclosed as discontinued operations when continuing cash flows are eliminated and when there is no significant continuing involvement with the component. EITF 03-13 provides additional guidance on factors to consider in evaluating what constitutes continuing cash flows and continuing significant influence. This Statement is effective for fiscal periods beginning after December 15, 2004. The Company does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the guidance.

Reserves of Crude Oil, Natural Gas Liquids, Natural Gas, Bitumen and Synthetic Crude Oil

(Crude oil and equivalents in MMbbls; Natural gas in Bcf)

Proved Reserves Before Royalties^{1, 2, 3, 4, 5}

	INTERNATIONAL						
	NORTHWEST EUROPE ⁶		NORTH AFRICA/ NEAR EAST ^{7, 8, 9, 10}		NORTHERN LATIN AMERICA ^{7, 11}	SUBTOTAL	
	Crude oil & natural gas liquids (NGL)	Natural gas	Crude oil & NGL	Natural gas	Natural gas	Crude oil & NGL	Natural gas
Beginning of year 2003	62	160	289	77	341	351	578
Revisions of previous estimates ¹⁵	14	(8)	24	—	—	38	(8)
Sale of reserves in place	—	(4)	—	—	—	—	(4)
Purchase of reserves in place	3	7	—	—	—	3	7
Discoveries, extensions and improved recovery	—	—	—	—	6	—	6
Production	(14)	(29)	(52)	(12)	(23)	(66)	(64)
End of year 2003	65	126	261	65	324	326	515
Revisions of previous estimates ¹⁵	12	31	1	(18)	(33)	13	(20)
Sale of reserves in place	—	(1)	(6)	—	—	(6)	(1)
Purchase of reserves in place	86	6	—	—	—	86	6
Discoveries, extensions and improved recovery	—	—	—	—	—	—	—
Production	(15)	(31)	(46)	(8)	(26)	(61)	(65)
End of year 2004	148	131	210	39	265	358	435

Proved Undeveloped Reserves¹⁶

Beginning of year 2003	10	22	51	—	275	61	297
End of year 2003	—	—	36	—	190	36	190
End of year 2004	101	14	21	—	178	122	192

- 1 In order to harmonize its oil and gas disclosure in both Canada and the U.S., Petro-Canada applied for, and received, certain exemptions to reserves disclosure requirements as set out in National Instrument NI 51-101; *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). These exemptions permit Petro-Canada to use its own staff of qualified reserves evaluators to prepare the Company's reserves estimates and to use U.S. Securities and Exchange Commission (SEC) and Financial Accounting Standards Board (FASB) standards when preparing and reporting reserves. Such reserves information may differ from reserves information prepared in accordance with Canadian disclosure standards under NI 51-101. These differences relate to the SEC requirement for disclosure only of proved reserves calculated at constant year-end prices and costs while NI 51-101 requires disclosure of proved reserves at constant prices and costs and proved plus probable reserves at forecast prices and costs. Also, the definition of proved reserves differs between SEC and NI 51-101 requirements. However, this difference should not be material. The Canadian Oil and Gas Evaluation Handbook (the source document for reserves definitions under NI 51-101) supports this view.
- 2 Petro-Canada employs the services of independent third-party evaluators/auditors to assess its reserves policies, practices and procedures and its reserves estimates.
- 3 Proved reserves before royalties are Petro-Canada's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty reflect net over-riding royalty interests paid and received.

- 4 Proved reserves are the estimated quantities of crude oil, natural gas and NGL which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves that are expected to be recovered from existing wells or facilities. Proved undeveloped reserves are proved reserves which are not recoverable from existing wells or facilities, but which are expected to be recovered through additional development drilling or through the upgrading of existing or additional new facilities.
- 5 Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.
- 6 Reserves in Northwest Europe are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in The Netherlands.
- 7 Proved reserves include quantities of crude oil and natural gas which will be produced under arrangements which involve the Company or its subsidiaries in upstream risks and rewards, but do not transfer title of the product to those companies.
- 8 Reserves in Syria and Algeria (and formerly in Kazakhstan) are held under production-sharing arrangements with the governments. The State share is split between royalty and tax for Canadian reporting purposes.
- 9 With the exception of the En Naga field, reserves in Libya are held under a concession and are subject to a royalty and tax regime. The En Naga field is held under a production-sharing arrangement, with the government's share being split between royalty and tax for Canadian reporting purposes.

	NORTH AMERICA – CONVENTIONAL										TOTAL	
	NORTH AMERICAN NATURAL GAS				EAST COAST ¹²	OIL SANDS ¹³	SUBTOTAL		TOTAL CONVENTIONAL	SYNCRUDE MINING OPERATION ¹⁴		
	WESTERN CANADA		U.S. ROCKIES									
	Crude oil & NGL	Natural gas	Crude oil & NGL	Natural gas	Crude oil & NGL	Bitumen	Crude oil & NGL	Natural gas	Crude oil, NGL & bitumen	Synthetic crude oil	Crude oil & equivalents	Natural gas
	55	2,181	–	–	68	32	155	2,181	506	324	830	2,759
	(1)	6	–	–	35	–	34	6	72	15	87	(2)
	(8)	(25)	–	–	–	–	(8)	(25)	(8)	–	(8)	(29)
	–	13	–	–	–	–	–	13	3	–	3	20
	1	106	–	–	–	–	1	106	1	–	1	112
	(6)	(251)	–	–	(32)	(4)	(42)	(251)	(108)	(9)	(117)	(315)
	41	2,030	–	–	71	28	140	2,030	466	330	796	2,545
	–	16	–	(14)	26	(22)	4	2	17	12	29	(18)
	–	(1)	–	–	–	–	–	(1)	(6)	–	(6)	(2)
	–	7	6	109	–	–	6	116	92	–	92	122
	2	145	–	–	–	–	2	145	2	–	2	145
	(5)	(247)	–	(7)	(29)	(6)	(40)	(254)	(101)	(11)	(112)	(319)
	38	1,950	6	88	68	–	112	2,038	470	331	801	2,473
	3	205	–	–	16	17	36	205	97	147	244	502
	1	82	–	–	16	17	34	82	70	165	235	272
	1	82	2	24	19	–	22	106	144	189	333	298

10 The volume of oil and gas reserves before royalties reported above held under production-sharing contracts in the North Africa/Near East Region at the end of 2004 was 72 MMbbls of crude oil and NGL and 39 Bcf of natural gas. At year-end 2003, the volume was 112 MMbbls of crude oil and NGL and 65 Bcf of natural gas. The after royalty reserves volumes were: year-end 2004 – 28 MMbbls of crude oil and NGL and 13 Bcf of natural gas; and year-end 2003 – 44 MMbbls of crude oil and NGL and 22 Bcf of natural gas.

11 Natural gas reserves in Trinidad are held under a production-sharing arrangement with the government. The State share is split between royalty and tax for Canadian reporting purposes. The volume of proved natural gas reserves before royalties reported above held under production-sharing contracts in Trinidad at the end of 2004 was 265 Bcf. At year-end 2003, the volume was 324 Bcf. The after royalty reserves volumes were: year-end 2004 – 225 Bcf; and year-end 2003 – 275 Bcf.

12 Proved reserves at Hibernia and Terra Nova are based on primary recovery for drilled fault blocks plus incremental recovery in fault blocks showing response to water or gas injection. Additional reserves quantities will be booked as proved reserves as development proceeds.

13 Proved reserves at MacKay River are based on estimates of recovery from existing producer-injector well pairs. As a result of very wide light/heavy crude oil differentials and high prices for synthetic crude oil used for blending at year-end 2004, bitumen prices were very low. Based on SEC practices for the estimation of proved reserves, the Company transferred its remaining proved reserves of bitumen at year-end to probable reserves.

14 Proved reserves of synthetic crude oil from the Syncrude oil sands mining operation in Northeastern Alberta are separately identified from reserves of conventional crude oil. Petro-Canada views these reserves as an integral part of the Company's business. Proved reserves of synthetic crude oil are based on high geological certainty and application of proven or piloted technology. For proved reserves, drill-hole spacing is less than 500 metres and appropriate co-owner and regulatory approvals are in place.

15 Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

16 Proved undeveloped conventional crude oil and NGL reserves represent approximately 31% of Petro-Canada's total conventional crude oil and NGL proved reserves. The vast majority of these oil and NGL reserves are associated with large development projects currently producing or under active development including Buzzard, White Rose, Terra Nova and Hibernia. Our proved undeveloped gas reserves represent approximately 12% of total proved natural gas reserves. These reserves typically will be developed through tie-in of existing wells, drilling of additional wells or addition of compression facilities. Sixty per cent of the proved undeveloped gas reserves are associated with the currently producing NCMA-1 development in Trinidad. Generally, the Company would plan to develop proved undeveloped natural gas reserves in the next few years.

Reserves of Crude Oil, Natural Gas Liquids, Natural Gas, Bitumen and Synthetic Crude Oil *continued*

(Crude oil and equivalents in MMbbls; Natural gas in Bcf)

Proved Reserves After Royalties^{1, 2, 3, 4, 5}

	INTERNATIONAL						
	NORTHWEST EUROPE ⁶		NORTH AFRICA/ NEAR EAST ^{7, 8, 9, 10}		NORTHERN LATIN AMERICA ^{7, 11}	SUBTOTAL	
	Crude oil & NGL	Natural gas	Crude oil & NGL	Natural gas	Natural gas	Crude oil & NGL	Natural gas
Beginning of year 2003	62	160	183	19	287	245	466
Revisions of previous estimates ¹⁵	14	(8)	14	5	6	28	3
Sale of reserves in place	—	(4)	—	—	—	—	(4)
Purchase of reserves in place	2	7	—	—	—	2	7
Discoveries, extensions and improved recovery	—	—	—	—	5	—	5
Production	(14)	(29)	(28)	(2)	(23)	(42)	(54)
End of year 2003	64	126	169	22	275	233	423
Revisions of previous estimates ¹⁵	13	31	3	(8)	(32)	16	(9)
Sale of reserves in place	—	(1)	(3)	—	—	(3)	(1)
Purchase of reserves in place	86	6	—	—	—	86	6
Discoveries, extensions and improved recovery	—	—	—	—	—	—	—
Production	(15)	(31)	(25)	(1)	(18)	(40)	(50)
End of year 2004	148	131	144	13	225	292	369

Proved Undeveloped Reserves¹⁶

Beginning of year 2003	10	22	33	—	232	43	254
End of year 2003	—	—	23	—	161	23	161
End of year 2004	101	14	14	—	151	115	165

- In order to harmonize its oil and gas disclosure in both Canada and the U.S., Petro-Canada applied for, and received, certain exemptions to reserves disclosure requirements as set out in National Instrument *NI 51-101; Standards of Disclosure for Oil and Gas Activities* (NI 51-101). These exemptions permit Petro-Canada to use its own staff of qualified reserves evaluators to prepare the Company's reserves estimates and to use U.S. Securities and Exchange Commission (SEC) and Financial Accounting Standards Board (FASB) standards when preparing and reporting reserves. Such reserves information may differ from reserves information prepared in accordance with Canadian disclosure standards under NI 51-101. These differences relate to the SEC requirement for disclosure only of proved reserves calculated at constant year-end prices and costs while NI 51-101 requires disclosure of proved reserves at constant prices and costs and proved plus probable reserves at forecast prices and costs. Also, the definition of proved reserves differs between SEC and NI 51-101 requirements. However, this difference should not be material. The Canadian Oil and Gas Evaluation Handbook (the source document for reserves definitions under NI 51-101) supports this view.
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NORTH AMERICA – CONVENTIONAL											TOTAL	
NORTH AMERICAN NATURAL GAS										SYNCRUDE MINING OPERATION ¹⁴		
WESTERN CANADA		U.S. ROCKIES		EAST COAST ¹²	OIL SANDS ¹³	SUBTOTAL		TOTAL CONVENTIONAL			Crude oil & equivalents	Natural gas
Crude oil & NGL	Natural gas	Crude oil & NGL	Natural gas	Crude oil & NGL	Bitumen	Crude oil & NGL	Natural gas	Crude oil, NGL & bitumen	Synthetic crude oil			
43	1,673	–	–	60	31	134	1,673	379	278		657	2,139
–	4	–	–	38	1	39	4	67	21		88	7
(7)	(19)	–	–	–	–	(7)	(19)	(7)	–		(7)	(23)
–	10	–	–	–	–	–	10	2	–		2	17
1	81	–	–	–	–	1	81	1	–		1	86
(5)	(190)	–	–	(31)	(4)	(40)	(190)	(82)	(9)		(91)	(244)
32	1,559	–	–	67	28	127	1,559	360	290		650	1,982
–	20	–	(11)	21	(22)	(1)	9	15	7		22	–
–	(1)	–	–	–	–	–	(1)	(3)	–		(3)	(2)
–	5	4	90	–	–	4	95	90	–		90	101
2	113	–	–	–	–	2	113	2	–		2	113
(4)	(188)	–	(6)	(27)	(6)	(37)	(194)	(77)	(10)		(87)	(244)
30	1,508	4	73	61	–	95	1,581	387	287		674	1,950
3	157	–	–	14	16	33	157	76	126		202	411
1	62	–	–	16	16	33	62	56	143		199	223
1	65	2	20	16	–	19	85	134	161		295	250

10 The volume of oil and gas reserves before royalties reported above held under production-sharing contracts in the North Africa/Near East Region at the end of 2004 was 72 MMbbls of crude oil and NGL and 39 Bcf of natural gas. At year-end 2003, the volume was 112 MMbbls of crude oil and NGL and 65 Bcf of natural gas. The after royalty reserves volumes were: year-end 2004 – 28 MMbbls of crude oil and NGL and 13 Bcf of natural gas; and year-end 2003 – 44 MMbbls of crude oil and NGL and 22 Bcf of natural gas.

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Quarterly Financial and Stock Trading Information

(unaudited, stated in millions of dollars, unless otherwise indicated)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 2004	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 2003
Revenue								
Operating	\$ 3,439	\$ 3,653	\$ 3,788	\$ 3,807	\$ 3,737	\$ 2,904	\$ 3,142	\$ 3,104
Investment and other income	34	(88)	(166)	(90)	(15)	53	(24)	(2)
	3,473	3,565	3,622	3,717	3,722	2,957	3,118	3,102
Expenses								
Crude oil and product purchases	1,473	1,666	1,807	1,794	1,640	1,232	1,346	1,402
Operating, marketing and general	655	669	664	702	618	608	675	656
Exploration	45	65	49	76	121	59	53	38
Depreciation, depletion and amortization	355	343	352	352	349	297	449	465
Unrealized gain (loss) on translation of foreign currency denominated long-term debt	16	26	(67)	(52)	(97)	(99)	(5)	(50)
Interest	37	38	33	34	48	45	46	43
	2,581	2,807	2,838	2,906	2,679	2,142	2,564	2,554
Earnings Before Income Taxes	892	758	784	811	1,043	815	554	548
Provision for Income Taxes	379	365	374	370	464	231	265	350
Net Earnings	\$ 513	\$ 393	\$ 410	\$ 441	\$ 579	\$ 584	\$ 289	\$ 198
Cash Flow From Operating Activities								
Before Changes In Non-cash Working Capital	\$ 921	\$ 885	\$ 895	\$ 1,046	\$ 991	\$ 874	\$ 879	\$ 628
Earnings								
Upstream								
North American Natural Gas	\$ 119	\$ 133	\$ 117	\$ 131	\$ 163	\$ 142	\$ 91	\$ 63
East Coast Oil	186	182	190	153	162	157	139	139
Oil Sands	34	25	51	10	12	11	20	(95)
International	123	72	93	84	64	70	113	50
Downstream	87	92	40	91	130	126	(27)	34
Shared Services	(32)	(33)	(30)	(30)	(46)	(55)	(40)	(41)
Earnings from operations	517	471	461	439	485	451	296	150
Foreign currency translation	(13)	(21)	54	43	94	98	4	43
Unrealized loss on Buzzard derivative contracts	—	(57)	(107)	(41)	—	—	—	—
Gain (loss) on sale of assets	9	—	2	—	—	35	(11)	5
Net earnings	\$ 513	\$ 393	\$ 410	\$ 441	\$ 579	\$ 584	\$ 289	\$ 198
Share Information (dollars per share)								
Earnings								
— Basic	\$ 1.93	\$ 1.48	\$ 1.54	\$ 1.69	\$ 2.19	\$ 2.20	\$ 1.09	\$ 0.75
— Diluted	1.90	1.46	1.52	1.67	2.16	2.17	1.08	0.74
Cash flow from operating activities								
before changes in non-cash working capital	3.46	3.32	3.37	4.01	3.75	3.30	3.31	2.37
Dividends	0.15	0.15	0.15	0.15	0.10	0.10	0.10	0.10
Share price¹								
— High	68.65	64.67	68.15	68.23	54.01	56.31	56.54	64.55
— Low	55.85	56.49	55.85	61.17	47.40	45.75	51.75	51.96
— Close (end of period)	\$ 57.62	\$ 57.65	\$ 65.74	\$ 61.17	\$ 50.00	\$ 53.96	\$ 52.49	\$ 63.91
Shares traded (millions)²	79.1	60.0	82.7	95.5	50.6	49.6	32.0	37.8

¹ Share prices are for trading on the TSX.

² Total shares traded on the TSX and NYSE.

Three-Year Financial and Operating Summary

(stated in millions of dollars, unless otherwise indicated)

	2004	2003	2002
Consolidated			
Revenue	\$ 14,377	\$ 12,899	\$ 10,374
Expenses	11,132	9,939	8,576
Provision for income taxes	1,488	1,310	843
Net earnings	\$ 1,757	\$ 1,650	\$ 955
Cash flow from operating activities before changes in non-cash working capital	3,747	3,372	2,276
Total assets	18,100	14,774	13,544
Average capital employed	10,533	9,268	7,722
Operating return on capital employed (%) ¹	18.8	16.1	14.5
Return on capital employed (%)	17.5	19.0	13.8
Debt	2,580	2,229	3,057
Debt-to-debt plus equity (%)	22.8	22.7	35.1
Debt to cash flow (times)	0.7	0.7	1.3
Expenditures on property, plant and equipment and exploration	4,073	2,315	1,861
Employees (number at year end)	4,788	4,514	4,470
Shareholders' Data			
Weighted-average number of common shares outstanding (millions)	264.6	264.9	262.8
Shares outstanding at year end (millions) ²	260.0	265.6	263.6
Publicly held shares at year end (millions)	260.0	216.2	214.2
Share prices (dollars) ³			
– at year end	61.17	63.91	48.91
– range during the year	56.50-68.65	45.75-64.55	33.90-50.15
Shares traded (millions) ⁴	315.9	169.9	196.4
Book value per share (dollars)	33.61	28.57	21.48

1 Earnings from operations are earnings before gains or losses on foreign currency translation and on disposal of assets and the unrealized loss on Buzzard derivative contracts.

2 Includes 49.4 million shares held as an investment by the Government of Canada for 2003 and 2002. On September 29, 2004, the Government of Canada completed its offering to the public of its entire remaining interest in Petro-Canada.

3 Year-end prices and ranges are from the TSX.

4 Total shares traded on the TSX and NYSE.

	2004	2003	2002
North American Natural Gas			
Earnings from operations	\$ 500	\$ 459	\$ 169
Gain (loss) on sale of assets	–	33	(1)
Net earnings	\$ 500	\$ 492	\$ 168
Cash flow from operating activities before changes in non-cash working capital	940	985	534
Expenditures on property, plant and equipment and exploration	724	560	530
Daily production (before/after royalties)			
Crude oil and liquids (thousands of barrels)	15.3/11.4	16.9/12.6	18.9/14.2
Natural gas (millions of cubic feet)	695/530	693/521	722/557
Proved reserves (before/after royalties)			
Crude oil and liquids (millions of barrels)	44/34	41/32	55/43
Natural gas (billions of cubic feet)	2,038/1,581	2,030/1,559	2,181/1,673
Oil and gas landholdings (gross/net) (millions of acres)	14.9/11.3	14.3/10.6	14.0/10.4
Wells drilled (gross/net)			
Oil	7/2	9/2	4/4
Natural gas	642/496	412/248	348/203
Dry	26/19	37/30	29/20
Suspended	0/0	1/1	0/0
Total	675/517	459/281	381/227

Three-Year Financial and Operating Summary *continued*

	2004	2003	2002
East Coast Oil			
Earnings from operations and net earnings	\$ 711	\$ 597	\$ 428
Cash flow from operating activities before changes in non-cash working capital	996	869	687
Expenditures on property, plant and equipment and exploration	278	344	289
Daily production <i>(before/after royalties)</i>			
Crude oil and liquids <i>(thousands of barrels)</i>	78.2/75.1	86.1/84.0	71.9/70.9
Proved reserves <i>(before/after royalties)</i>			
Crude oil and liquids <i>(millions of barrels)</i>	68/61	71/67	68/60
Oil and gas landholdings <i>(gross/net) (millions of acres)</i>	3.6/1.2	4.3/1.5	5.1/1.7
Wells drilled <i>(gross/net)</i>			
Oil	17/4	12/3	13/3
Dry	0/0	3/1	3/1
Total	17/4	15/4	16/4
Oil Sands			
Earnings (loss) from operations and net earnings	\$ 120	\$ (52)	\$ 78
Cash flow from operating activities before changes in non-cash working capital	334	127	196
Expenditures on property, plant and equipment and exploration	399	448	462
Daily production <i>(before/after royalties)</i>			
Bitumen <i>(thousands of barrels)</i>	16.6/16.5	10.7/10.6	1.1/1.0
Synthetic crude oil <i>(thousands of barrels)</i>	28.6/28.3	25.4/25.1	27.5/27.2
Proved reserves <i>(before/after royalties)</i>			
Bitumen <i>(millions of barrels)</i>	0/0	28/28	32/31
Synthetic crude oil <i>(millions of barrels)</i>	331/287	330/290	324/278
Oil and gas landholdings <i>(gross/net) (millions of acres)</i>	0.6/0.3	0.6/0.3	0.9/0.3
Wells drilled <i>(gross/net)</i>			
Oil Sands – bitumen	0/0	0/0	0/0
Dry	0/0	0/0	0/0
Total	0/0	0/0	0/0
International			
Earnings from operations	\$ 372	\$ 297	\$ 225
Gain on sale of assets	8	10	—
Unrealized loss on Buzzard derivative contracts	(205)	—	—
Net earnings	\$ 175	\$ 307	\$ 225
Cash flow from operating activities before changes in non-cash working capital	1,027	890	583
Expenditures on property, plant and equipment and exploration	1,824	525	221
Daily production <i>(before/after royalties)</i>			
Crude oil and liquids <i>(thousands of barrels)</i>	167.0/107.8	180.8/115.6	125.5/75.2
Natural gas <i>(millions of cubic feet)</i>	178/138	175/149	103/81
Proved reserves <i>(before/after royalties)</i>			
Crude oil and liquids <i>(millions of barrels)</i>	358/292	326/233	351/245
Natural gas <i>(billions of cubic feet)</i>	435/369	515/423	578/466
Oil and gas landholdings <i>(gross/net) (millions of acres)</i>	13.4/7.9	12.5/7.2	12.9/7.2
Wells drilled <i>(gross/net)</i>			
Oil	56/24	54/21	39/17
Natural gas	2/0	6/1	5/1
Dry	16/6	12/6	9/4
Total	74/30	72/28	53/22
Downstream			
Earnings from operations	\$ 310	\$ 263	\$ 249
Gain (loss) on sale of assets	4	(15)	3
Net earnings	\$ 314	\$ 248	\$ 252
Cash flow from operating activities before changes in non-cash working capital	556	601	380
Expenditures on property, plant and equipment	839	424	344
Petroleum product sales <i>(thousands of cubic metres per day)</i>	56.6	56.8	55.7
Retail outlets at year end	1,375	1,432	1,537
Refinery crude capacity at year end <i>(thousands of cubic metres per day)</i>	49.0 ¹	49.8	49.8
Average refinery utilization (%)	98	100	101

¹ Capacity revised, on a pro rata basis, from 49,800 cubic metres per day (313,000 b/d) in 2003 to reflect partial closure of Oakville refinery operations, effective November 12, 2004.

Corporate Governance

CORPORATE GOVERNANCE PRACTICES

Principles

As an international and publicly traded oil and gas company, Petro-Canada recognizes the importance of adhering to superior corporate governance standards. The Company has developed sound corporate governance policies and procedures, which are monitored and reviewed on a continuous basis, and adopts a “best practices” approach in all of its corporate governance initiatives. The Company’s Board of Directors, management and employees believe that strong corporate governance is essential to the creation of shareholder value and maintaining the confidence of investors. The Corporate Governance and Nominating Committee is responsible for monitoring the development of, and compliance with, corporate governance policies and procedures.

Board of Directors

The Board of Directors is responsible for overseeing the management of Petro-Canada’s business and affairs. The Board of Directors has the statutory authority and obligation to act in good faith, with a view to protect and enhance the value of the Company, in the interest of all shareholders. To this end, members of the Board of Directors are expected to exercise independent judgment with the utmost honesty and integrity, adhering to all Company policies and procedures, legal requirements and regulatory regimes.

Composition of the Board of Directors

The Articles of the Company require the Board of Directors to be comprised of a minimum of nine and a maximum of 13 directors. The Board of Directors is currently comprised of 13 members and following the Annual Meeting will be decreased to 12. The number of Directors may be increased or decreased by resolution of the Board of Directors within the minimum and maximum numbers set forth in the Articles, depending on the size and complexity of Petro-Canada’s business, and the number of committees required to conduct the business of the Board of Directors.

The Company’s shareholders elect the Board of Directors at the Annual Meeting each year. The Corporate Governance and Nominating Committee is responsible for recommending director nominees to the Board of Directors, having regard to the competencies and skills required by the Board of Directors and the competencies and skills that potential nominees would bring to the Board of Directors, if elected.

Independence of the Board of Directors

Independence of the Board of Directors is essential to fulfilling its role in overseeing the Company’s business and affairs. All but one of the current Directors are “unrelated” under the Toronto Stock Exchange (TSX) Corporate Governance Guidelines and “independent” under Proposed National Instrument 58-101 (NI 58-101), the New York Stock Exchange (NYSE) Corporate Governance Standards and the *Sarbanes-Oxley Act of 2002 (SOX)*.¹ Ron A. Brenneman, Petro-Canada’s president and chief executive officer, is not unrelated or independent. The Board of Directors has determined that no other Director is in a relationship with the Company that would preclude such Director’s status as unrelated or independent under the foregoing rules and policies. To further the Company’s aim to maintain Director independence, the Board of Directors holds *in camera* sessions during each meeting without management present.

¹ Further detail regarding these regulations can be found on page 79 under “Legislative and Regulatory Requirements.”

Responsibilities of the Board of Directors

The Board of Directors oversees the management of Petro-Canada's business and affairs, which is done through the day-to-day management of the Company by the president and chief executive officer and the executive leadership team. The principal duties of the Board of Directors include the following:

- managing its own affairs, including planning its composition, selecting its chair, appointing committees and their chairs, establishing Board of Directors and committee procedures, and determining Director compensation;
- determining the selection, retention, succession and compensation of senior management;
- conducting an annual performance evaluation of the president and chief executive officer and establishing a list of special objectives for the ensuing year;
- reviewing and approving the mission of Petro-Canada's business, its objectives and goals, and the strategy for their achievement;
- monitoring the Company's progress toward its goals, and taking action to fulfill those goals;
- approving and monitoring compliance with all significant policies and procedures by which the Company is operated;
- reviewing and approving the financial statements, business plan and capital budget of the Company;
- overseeing the accurate and timely reporting to shareholders and regulators of the Company's performance, financial statements and significant developments; and
- approving any significant new venture that is outside the Company's ordinary course of business, any expenditure not included in the annual budget approved by the Board of Directors and any transaction of a value in excess of \$75 million.

Review of the Board of Directors

The chair of the Board of Directors provides leadership in regard to the work of the Board of Directors committees and the effective performance of the Board of Directors, including a process for evaluation of Board of Directors performance. Each year, the chairs of the Management Resources and Compensation Committee and the Corporate Governance and Nominating Committee, in consultation with other members of the Board of Directors, review the performance of the chair of the Board of Directors and set objectives for the coming year. The Corporate Governance and Nominating Committee leads an annual process to evaluate the Board of Directors, and the Board of Directors informally reviews its own performance at the end of each Board of Directors meeting. Individual Directors complete an annual self-assessment, which is reviewed by the chair of the Corporate Governance and Nominating Committee and discussed with the Board of Directors.

Committees of the Board of Directors

The Board of Directors currently has the following five standing committees:

- Audit, Finance and Risk Committee;
- Corporate Governance and Nominating Committee;
- Management Resources and Compensation Committee;
- Pension Committee; and
- Environment, Health and Safety Committee.

Each committee typically has five members, each of whom are "unrelated" under the TSX Corporate Governance Guidelines, and "independent" under NI 58-101 and the NYSE Corporate Governance Standards. Ron A. Brenneman, Petro-Canada's president and chief executive officer, is not a member of any of the committees, but may sit in on any or all committee meetings, except the *in camera* portion.

Each committee undertakes detailed examinations of specific aspects of the Company. Committee meetings provide a smaller, more intimate forum than full Board of Directors meetings and are designed to be more conducive to exhaustive and forthright discussion. The chair of each committee provides a report to the Board of Directors following each committee meeting.

Corporate Governance Handbook

For additional detail regarding the Board of Directors and its committees, please see the Company's 2005 Management Proxy Circular. In addition, the Board Mandate, Committee Terms of Reference and certain executive position descriptions can be found in the Corporate Governance Handbook on the Company's Web site at www.petro-canada.ca.

Legislative and Regulatory Requirements

The Board of Directors must act in accordance with the Company's Articles and Bylaws, the *Petro-Canada Public Participation Act*, the *Canada Business Corporations Act*, and securities, environmental and other relevant legislation.

Canada: NI 58-101, Proposed National Policy 58-201 (NP 58-201) and the TSX Corporate Governance Guidelines

In Canada, Petro-Canada's shares are listed on the TSX. The TSX requires each listed company to annually discuss its approach to corporate governance. Petro-Canada's disclosure must refer to each of the TSX Corporate Governance Guidelines and, where the Company's approach is different from any of those guidelines or where the guidelines do not apply, must explain the differences or their inapplicability. In addition, the Canadian securities regulators have proposed NP 58-201 and NI 58-101, which also provide for detailed corporate governance requirements. It is anticipated that NI 58-101 will be adopted and apply to fiscal years ending on or after June 30, 2005.

Although listed companies are not yet required to comply with proposed NI 58-101, Petro-Canada has detailed its compliance with NI 58-101 on the Company's Web site at www.petro-canada.ca. The Company's existing corporate governance practices comply with the TSX Corporate Governance Guidelines, the details of which can be found in the Company's 2005 Management Proxy Circular.

United States: NYSE Listing Standards and SOX

In the United States (U.S.), Petro-Canada's shares are listed on the NYSE. As a foreign private issuer in the U.S., Petro-Canada is not required to comply with most of the NYSE Corporate Governance Listing Standards. However, the Company is required to disclose the significant differences between its corporate governance practices and the requirements applicable to U.S. domestic issuers listed on the NYSE. In addition, as of July 31, 2005, Petro-Canada is required to comply with certain audit committee requirements set out in the NYSE listing standards.

Petro-Canada is substantially in compliance with the current NYSE Corporate Governance Listing Standards and audit committee requirements. There are no significant differences between Petro-Canada's corporate governance practices and those required of U.S. domestic issuers under the NYSE Listing Standards. Petro-Canada has continued to adjust its practices to reflect the requirements of the NYSE Listing Standards and SOX. This includes commencing the process of revising the written mandates for the Board of Directors and the Board of Directors committees to provide for additional detail as to their purpose, responsibilities and procedures. In addition, the Company has instituted a whistleblower hotline for employees to anonymously report matters to the chief compliance officer and the chair of the Audit, Finance and Risk Committee. Petro-Canada has a Code of Business Conduct applicable to all Directors, officers and employees and a Code of Ethics for its senior financial officers.

Additional detail regarding Petro-Canada's alignment with the NYSE Corporate Governance Listing Standards and compliance with SOX can be found on the Company's Web site at www.petro-canada.ca.

EXECUTIVE LEADERSHIP TEAM*

Ron A. Brenneman
President and
Chief Executive Officer

Peter S. Kallos
Executive Vice-President,
International

Boris J. Jackman
Executive Vice-President,
Downstream

E.F.H. Roberts
Executive Vice-President and
Chief Financial Officer

Kathleen E. Sendall
Senior Vice-President,
North American Natural Gas

Brant G. Sangster
Senior Vice-President,
Oil Sands

Gordon Carrick
Vice-President,
East Coast Oil

BOARD OF DIRECTORS*

Ron A. Brenneman
President and
Chief Executive Officer
Petro-Canada

Angus A. Bruneau, O.C.
Chairman of the Board
Fortis Inc.

Gail Cook-Bennett
Chairperson
Canada Pension Plan
Investment Board

Richard J. Currie
Chairman of the Board
BCE Inc.

Claude Fontaine
Senior Partner
Ogilvy Renault

Paul Haseldonckx
Corporate Director

Thomas E. Kierans, O.C.
Chairman
Canadian Institute for
Advanced Research

Brian F. MacNeill
Chairman of the Board
Petro-Canada

Maureen McCaw
President
Criterion Research Corp.

Paul D. Melnuk
Chairman and
Chief Executive Officer
Thermadyne Holdings
Corporation and
Managing Partner
FTL Capital Partners

Guylaine Saucier, F.C.A., C.M.
Corporate Director

William W. Siebens
President and
Chief Executive Officer
Candor Investments Ltd.

James W. Simpson
Corporate Director

SECRETARY TO THE BOARD OF DIRECTORS

Hugh L. Hooker
Associate General Counsel
and Corporate Secretary

* As of March 3, 2005.

Please see the 2005 Management Proxy Circular for additional information about Petro-Canada's senior officers, Board of Directors and governance practices. The Management Proxy Circular contains: disclosure on executive compensation and contracts; reports of Board of Directors' committees and a description of each committee's responsibilities; a Statement of Corporate Governance Practices; and detail on Directors' business background, tenure, committee membership, remuneration and share ownership. The Management Proxy Circular is available for viewing on our Web site at www.petro-canada.ca or by contacting Investor Relations.

INVESTOR INFORMATION

Outstanding Shares

At December 31, 2004, Petro-Canada's public float was 260,025,211 shares.

Transfer Agent and Registrar

In Canada:

CIBC Mellon Trust Company

In the United States:

Mellon Investor Services, LLC

Telephone toll free: 1-800-387-0825

Fax: (416) 643-5660 or

(416) 643-5661

E-mail: inquiries@cibcmellon.com

Web site: www.cibcmellon.com

Duplicate Reports

Shareholders with more than one unregistered account may receive duplicate materials. To eliminate duplicate mailings, contact your broker. Registered shareholders should contact the transfer agent and registrar.

Annual and Special Meeting

The Annual and Special meeting of Shareholders will be held at 11:00 a.m. local time on Tuesday, April 26, 2005, at The Fairmont Palliser Hotel, Crystal Ballroom, 133-9 Avenue S.W., Calgary, Alberta.

Stock Exchange Listings and Symbols

Toronto: PCA

New York: PCZ

Dividends

Petro-Canada's Board of Directors pays quarterly dividends of \$0.15 (\$0.60 per annum) per common share. The Board of Directors regularly reviews the dividend strategy to ensure alignment with shareholders' expectations and financial and growth objectives.

On The Web Site

Petro-Canada's Web site, www.petro-canada.ca, contains a variety of corporate and investor information, including:

- Statistical Supplement
- Annual Information Form
- Quarterly Reports
 - Management Proxy Circular
 - Corporate Governance Practices

- Presentations and Webcasts
- Dividend History
- Petro-Canada's Code of Business Conduct
- Petro-Canada's Principles for Investment and Operations
- Report to the Community

Investor Inquiries

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E-mail: investor@petro-canada.ca

Media Inquiries

Corporate Communications

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General Inquiries

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Fax: (403) 296-3030

Web site: www.petro-canada.ca

We Would Like Your Feedback

We invite your comments on our Annual Report. Please e-mail your comments to: ARANSON@petro-canada.ca



GENERAL INQUIRIES

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To learn more about Petro-Canada,
please visit our Web site at www.petro-canada.ca